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BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES	Docket No. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606	Docket No. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	Docket No. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES	Docket No. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY	Docket No. E-01933A-98-0471

NOTICE OF FILING DIRECT TESTIMONY

Staff hereby provides notice of filing Direct Testimony in this docket. An original and ten copies are submitted of the Direct Testimony of Matthew Rowell, Jerry D. Smith, Erinn A. Andreasen, Barbara E. Keene, Paul R. Peterson, Neil H. Talbot and David A. Schlissel.

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RESPECTFULLY SUBMITTED this 29th day of May, 2002.

Janet F. Wagner

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Original and ten copies of the foregoing filed this 29th day of May, 2002, with:

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Arizona Corporation Commission
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Copy of the foregoing mailed and by electronic e-mail this 29th day of May, 2002, to:

All parties of record

Nancy Roe

DIRECT TESTIMONY

OF

MATTHEW ROWELL
JERRY D. SMITH
ERINN A. ANDREASEN
BARBARA E. KEENE

DOCKET NO. E-00000A-02-0051

MAY 29, 2002

BEFORE THE ARIZONA CORPORATION COMMISSION

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DIRECT

TESTIMONY

OF

MATTHEW ROWELL

CHIEF: TELECOMMUNICATIONS AND ENERGY SECTION

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MAY 29, 2002

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INTRODUCTION

Q. Please state your name and business address for the record.

A. My name is Matthew Rowell. My business address is Arizona Corporation Commission, 1200 W. Washington, Phoenix, AZ 85007.

Q. By whom are you employed, and in what capacity?

A. I am employed by the Arizona Corporation Commission as the Chief of the Telecommunications and Energy section of the Commission's Utilities Division.

Q. Please describe your education and professional background.

A. I received a BS degree in economics from Florida State University in 1992. I spent the following four years doing graduate work at Arizona State University where I received a MS degree and successfully completed all course work and exams necessary for a Ph.D. My specialized fields of study were Industrial Organization and Statistics. I was hired by the Commission in October of 1996 as an Economist II. Prior to my Commission employment I was employed as a lecturer in economics at Arizona State University, as a statistical analyst for Hughes Technical Services, and as a research analyst at the Arizona Department of Transportation.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain in detail Staff's recommendations concerning the transfer and separation of generating assets and to provide a general outline of all of Staff's testimony. An explanation of the outline of all of Staff's testimony is necessary in order for the reader to be able to put the various testimonies into context.

Q. Can you explain the general outline of Staff's testimony?

A. Staff's testimony focuses on the issues identified in the May 2, 2002 Procedural Order:

- market power,
- transfer of generation assets,
- code of conduct
- jurisdictional issues.

These issues stem from the Commission's Retail Electric Competition Rules (Title 14, Article 16 of the Arizona Administrative Code) and the associated settlement agreements.

These rules and settlement agreements were originally intended to provide for the development of *retail* competition. However, retail competition has yet to develop in Arizona and retail competition as envisioned by the rules has yet to develop anywhere in the US. Staff is not of the opinion that the development of retail competition is on the near horizon. Thus, the issues that are currently before the Commission largely concern the development of *wholesale* competition. Staff's recommendations will focus on allowing a competitive wholesale market for power to develop. However, there is no guarantee that a competitive wholesale market actually will develop for Arizona. Thus, Staff's recommendations will also focus on ensuring that retail customers receive reliable power at just and reasonable rates (whether the wholesale market develops or not.) While the development of a competitive wholesale market may be a necessary precursor to retail competition, it is no guarantee that retail competition will follow. Staff contends that consumers may benefit from wholesale competition even if retail competition never occurs. Thus, Staff's testimonies should not be construed to imply that retail competition will (or will not) develop if Staff's recommendations are implemented.

Staff's testimonies follow the following basic outline:

- Neil Talbot provides justification for Staff's contention that there is a rebuttable presumption of market power on the part of incumbent utilities.
- David Schlissel's testimony discusses Staff's concerns regarding the market power that may result from the transfer and separation of generation assets from the incumbent utilities.
- Paul Peterson's testimony discusses recent developments at the FERC regarding standard market design and the recent restructuring experience of other states.
- Jerry Smith's testimony discusses the adequacy of Arizona's existing electric system and plans for new transmission lines.
- Barbara Keene's testimony explains Staff's concerns regarding transactions between affiliates in a post-transfer world and provides recommendations to address these concerns.
- Erinn Andreasen's testimony describes Staff's recommendation regarding the need for an Electric Competition Advisory Group.
- My testimony provides Staff's recommendations regarding the mitigation of market power resultant from the transfer of generation assets.

Q. Has the lack of retail competition in Arizona influenced Staff's recommendations?

A. Only indirectly. While the subject of this proceeding does not directly involve retail competition, consumers' lack of any real alternatives to the UDCs for the provision of electric service is a consideration. Presently, consumers have no viable alternative but to purchase power from their UDCs. The UDCs' cost of procuring power on the wholesale market will flow through to consumers in terms of retail rates. Captive consumers will be exposed to the procurement practices of the UDCs. Thus, those procurement practices will require scrutiny by the Commission.

OVERRIDING GOALS

Q. What is the overriding goal of Staff's recommendations?

A. The overriding goal of Staff's recommendations is to ensure that consumers will receive reliable electric service at just and reasonable rates. This, of course, is the Commission's constitutional mandate and is also one of the goals of traditional cost-of-service regulation. Staff believes it is important to ensure that consumers are no worse off under the restructured environment than they were under traditional cost-of-service regulation. As the restructuring of the electric utility industry continues, Staff is concerned that the goal of providing retail customers with reliable power at just and reasonable rates may be subverted. Staff believes that the *goal* of just and reasonable rates is the primary concern, the *process* that is used to get there is secondary. Focus on the process may result in a lack of focus on the goal. Staff's recommendations are intended to ensure that as restructuring continues the goal of reliable electric service at just and reasonable rates is not forgotten. Of course, many considerations enter into this inquiry. Staff understands that reliability is, and always will be, an essential consideration. Also, the financial health of the UDCs cannot be forgotten. Staff does not intend for its recommendations to impose undue restrictions on the UDCs. On the contrary, Staff believes that the UDCs must be afforded a great deal of flexibility in order for them to procure (or produce) power in a just and reasonable manner. However, the UDCs must be held accountable by the Commission for the decisions they make concerning the procurement (or production) of power.

Q. Why are existing cost of service rates relevant to competition?

A. The Commission, in every rate order it issues, concludes that the rates contained therein are just and reasonable. Accordingly, the utilities are currently charging just and reasonable rates. Traditionally, these regulated rates have been based on the utilities' reasonable cost of providing service plus a reasonable rate of return.

The proponents of electric competition hoped that competition would bring increased efficiencies to the industry, thereby lowering costs to the end user. But for these competitive efficiencies to come to fruition, it is necessary to have a number of competitive providers in the market. As I discussed earlier, this has simply not occurred. To date, Arizona has virtually no retail competition. And although some believe that the market for wholesale supply is adequate to support the competitive bid requirements of rule 1606(B), others have come to the opposite conclusion. Finally, even aside from issues about the number of potential competitors, there may not be adequate transmission to support a competitive market. In short, without new competitors and/or without adequate access to the market, the price benefits of competition will not develop.

In such circumstances, the Commission must determine what it can do to encourage the development of competition while at the same time protecting end users. Because we know that existing cost of service rates are just and reasonable, we can use them as a benchmark for evaluating competitive rates during this transitional period.

Q. **What do you mean by this transitional period mentioned in the previous question?**

A. The transitional period is the period from now until the Commission determines that the wholesale market for power delivered to the UDCs' service territories is workably competitive.

Q. **Can you explain Staff's recommendations that are specific to the goal of ensuring adequate electric service at just and reasonable rates?**

A. Yes. Staff believes that the UDCs must obtain or produce reliable power for Standard Offer customers at the best price. By the best price Staff means that the utility must choose the best combination of lowest price and lowest risk. Staff believes that UDCs should be free to obtain power through whatever means will result in the best price. This includes auctions, RFPs, negotiated bilateral contracts, self-generation, or any combination of these or other means. Auctions, RFPs and negotiated bilateral contracts may all result in purchase power agreements. The UDCs should develop a procurement strategy that is designed to provide adequate service to its customers at the best price. As part of their ongoing procurement planning process, the UDCs should be required to perform an assessment or analysis that demonstrates that they are obtaining and/or producing reliable power for Standard Offer customers at the best price.

Q. In your previous answer, you mentioned that UDCs could obtain power through a variety of means, including self-generation. How do you reconcile that recommendation with the requirements of A.A.C. R14-2-1615?

A. Staff believes that Rule 1615 should be modified. Specifically, Staff sees no reason at this time to *require* the transfer of all competitive generating assets to an affiliate. Staff does, however, believe that the utilities should have the discretion to effect such a transfer, as long as appropriate protections are in place.

Q. Does your recommendation regarding A.A.C. R14-2-1615 affect the implementation of A.A.C. R14-2-1606?

A. Yes, it potentially does. If a utility were to choose not to divest, the provisions of rule 1606(B) would likely not be achievable. But until we know what election the utilities make, it is premature to suggest specific changes to rule 1606(B). Applications for relief from 1606(B) should be supported by *demonstrated evidence* that the UDC attempted to comply with 1606(B) but that compliance was either not possible or would not result in just and reasonable rates.

Regardless of the provisions of rule 1606(B) the Commission should consider measures that ensure that consumers are no worse off because of competitive procurement than they would have been under traditional cost of service regulation. Specifically, during this transitional period, the established cost of service should be used as both a standard for UDC recovery and as the price to beat for any competitive solicitation process. Staff recommends that prudence reviews of purchases by UDCs from their affiliates or others should use the already established cost of service of the assets the utility has chosen to transfer as the baseline for the prudence evaluation. Also, the established cost of service for the utilities' existing generation units should be used as the price to beat during competitive solicitations whether the utility has transferred its generation assets or not. Generally, Staff does not believe it is appropriate for a UDC to procure power at a higher price than its own cost of service before transfer or its affiliate's cost of service after transfer. Of course, these standards could not be applied to cases where the UDC is procuring power to serve load which it, or its affiliate, does not have the capacity to serve (i.e., load growth beyond the utilities' current capacity.)

Q. Does Staff have any other recommendations concerning the procurement of power?

A. Yes, Staff recommends that the UDC should be responsible for obtaining power for its Standard Offer customers. The UDC should be prohibited from delegating this responsibility to any of its affiliates, including its parent company.

Transfer of Assets

Q. What are Staff's concerns with regards to the transfer of generating assets?

A. Staff believes that there is a rebuttable presumption that incumbent vertically integrated utilities posses market power.[1] The testimony of Neil Talbot demonstrates that such a presumption is reasonable and appropriate. Under the traditional regulatory regime, the Commission has the authority to hold the market power of the incumbent utilities in check. If the generating assets are transferred from an incumbent utility to its affiliate(s),

[1] By "market power" Staff means the ability to maintain artificially high prices for power *delivered to the UDC's service territory.*

Staff believes that the market power effectively stays the same but the Commission's ability to respond to it is weakened. Thus, although the market power may be no different in an abstract sense, the potential for market abuse is increased. The horizontal market power that the utility had in the generation market is simply transferred to the affiliate.[2] The vertical market power the utility possessed by virtue of it owning both generation and transmission assets may be somewhat complicated by the transfer; however, it is naive to believe that the affiliated generation and transmission companies would not have a strong economic incentive to act in concert to maintain their vertical market power in the absence of appropriate monitoring and mitigation measures.

While the market power of the company is effectively unchanged, the Commission's ability to mitigate that market power will change substantially as a result of the transfer of generating assets because the Commission will not be able to regulate the wholesale rates the generation owning affiliate charges for power. This includes the rates the generation owning affiliate charges the affiliated UDC. Thus, the generation owning affiliate (perhaps working in concert with the UDC) may be able to artificially inflate the price for power delivered into the UDC's service territory and pass that inflated price on to the UDC. The UDC would then in turn attempt to pass the inflated prices on to its retail customers. Thus, the goal of providing customers with reliable power at just and reasonable rates would not be realized.

The FERC does have some authority to prevent such market power abuses. However, recent experience suggests that the FERC may be slow to act. The FERC's standard market design proceeding is meant to address concerns regarding market power abuses. However, that proceeding is ongoing. As the testimony of Paul Peterson demonstrates,

[2] This would hold true if the generating assets were transferred in bulk to a non-affiliate as well. Such a transfer would have its own set of problems but since such a transfer is not being contemplated by any of the parties in AZ Staff will not dwell on that eventuality.

development of comprehensive structures and practices to conclusively alleviate market power abuse issues is difficult and time consuming. In the short run, reliance on FERC to control market power abuse is ill advised.

Implementing a strategy like the one outlined above is clearly in the economic interests of the utilities. If recent experience across the country has taught us anything, it is that power providers will have an economic incentive to game the system. It would be naive and unwise to leave the door open for such activity. Staff's recommendations are designed to allow restructuring to move forward while providing safeguards that prevent the above scenario from playing out.

Staff also believes that the timing of the asset transfers is problematic. There is currently a great deal of uncertainty regarding the electric industry that was not contemplated at the time the Retail Electric Competition Rules and Settlement agreements were finalized. Specifically, there are currently serious concerns regarding the delivery of natural gas into Arizona over El Paso's pipeline system (discussed in detail in Jerry Smith's testimony.) Also, FERC may lift the price caps imposed on the West this September and the FERC has not completed its standard market design proceeding.

Q. What are Staff's recommendations concerning the transfer of generation assets?

A. Staff has four basic recommendations regarding the transfer of generation assets:

1. Prior to the transfer of any generation assets, the utilities should be required to file a market power study and market power mitigation plan for Commission approval.
2. Generation assets identified as must-run units may only be transferred subsequent to the Commission's consideration of their must-run status.
3. Other generating units can be transferred at the utilities' discretion.
4. The recommendations concerning codes of conduct outlined in Barbara Keene's testimony should be implemented prior to transferring the assets.

MARKET POWER STUDIES

Q. What is the purpose of the market power study and the market power mitigation plan that Staff recommends the utilities must file for Commission approval before transferring their assets?

A. The purpose of that requirement is to provide the Commission with the information it needs to evaluate the appropriateness of taking the irrevocable step of transferring assets. The Commission may decide to impose market power mitigation requirements on the UDCs. Staff believes that it would be better for all involved that such analysis and decisions be made *before* the assets are transferred so that the utilities can make an informed choice about whether to transfer their generation assets and the Commission is aware of the state of the market.

Q. What are the minimum requirements of the market power study and the market power mitigation plan that Staff recommends?

A. The market power study and mitigation plan should contain enough relevant information for the Commission to make an informed decision. To that end, Staff recommends that at the time the study and plan are filed the utility should also file written testimony and exhibits which explain and identify in detail the quantitative data used in the analysis and the conclusions drawn from the analysis. The market power study should consider any and all factors that could adversely impact the ability of new or alternate suppliers to enter the Arizona retail or wholesale markets. The market power study shall examine horizontal and vertical market power, the effect on competition of distribution and transmission access and pricing, contractual arrangements, and other potential barriers to entry into the Arizona wholesale and retail electric market. The analysis of horizontal market power should be consistent with the U.S. Department of Justice and Federal Trade Commission's Horizontal Merger Guidelines, as revised April 8,1997 ("DOJFTC Merger Guidelines.") The DOJFTC Merger Guidelines, standards, and methods, which are designed to apply to mergers, should be adapted and modified as necessary to the circumstances specific to the deregulation of generation and the introduction of retail open access. The analyses should also be consistent with current FERC market power tests such as the pivotal supply test and analytical methods such as strategic behavior analysis. The horizontal market power analysis for retail and wholesale products should include analyses of market concentration and barriers to entry for non-affiliated providers for each customer class. The vertical market power analysis should demonstrate that the functional separation, codes of conduct, affiliate transactions, and interconnection and open access policies and tariffs are or will be structured and implemented to assure that all wholesale and retail competitors have access to the competitive markets equal to that of the utility and its ESP affiliates. If the results of the above described analysis reveal areas of concern the Commission may require that additional analysis be conducted such as strategic behavior analysis. The Arkansas Public Service Commission's Minimum Filing Requirements for Market Power Analysis approved on June 27, 2000, provides additional detail on the content of market power studies.

Q. What is the relevant market that should be considered when analyzing wholesale market power?

A. The relevant market to consider is the market for power *delivered into* the UDC's service territory. All practical and economic sources of generation should be included in the analysis.

Q. How will the market power studies and mitigation plans filed by the utilities be evaluated?

A. The Commission should evaluate the market power studies and mitigation plans to determine that the opportunity for competition exists. The Commission may seek input from relevant parties including Staff. Staff may request that the Electric Competition Advisory Group (described in the testimony of Erinn Andreasen) provide input for Staff's analysis. A hearing may be necessary if the issues raised by the market power study are contested.

Q. Is Staff's recommendation concerning market power studies and mitigation plans designed to delay the asset transfers provided for in the settlement agreements?

A. No, Staff's recommendation is designed only to ensure that proper safeguards accompany the transfer.

RELIABILITY MUST RUN GENERATION

Q. What does Staff recommend concerning the transfer of generating assets that are identified as reliability must run?

A. Staff is concerned that the existence of (reliability) must run units (as defined in A.A.C. R14-2-1601) will present serious market power concerns. The testimony of David Schlissel addresses these market power concerns in detail. Thus, Staff recommends that these units only be transferred after the Commission has considered their must run status and determined that they no longer have the potential to exercise market power. Potential options for relieving the reliability concerns associated with load pockets and reliability must run units are discussed in the testimony of Jerry Smith. Until these market power concerns are adequately addressed, Staff recommends that these reliability must run generation units should remain subject to rate regulation by the Commission and should not be able to participate in any competitive bidding for Standard Offer Service. Also, while these units are still owned by the UDC wholesale profits associated with them should be retained by the UDC for the benefit of its standard offer customers. This and other issues related to off system sales will be addressed in APS' next rate case.

Staff believes that its recommendations concerning reliability must run units are consistent with A.A.C. R14-2-1615 which calls for the separation of "competitive generation assets." A.A.C. R14-2-1601 (the definitions section of the Retail Electric Competition Rules) specifically classifies (reliability) must run generation as "Noncompetitive Services."

OTHER GENERATING UNITS

Q. What does Staff recommend concerning the transfer of generating assets that are not must run units?

A. Staff believes that these generation units can be transferred at the discretion of the utilities after the Commission has completed its review of their market power study discussed above. Staff believes that the utilities should be allowed to transfer their assets, even to an affiliate, but Staff sees little value in ***requiring*** them to do so. Staff sees little value to consumers in a bulk transfer of generating assets to an entity outside of the Commission's jurisdiction.[3] Thus, *forcing* utilities to do so does not seem appropriate at this time.

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[3] It could be argued that the separation of assets would make the competitive bidding process easier to manage. However, several states (e.g., Florida and Colorado) have implemented competitive bidding processes without the transfer of assets.

Q. After a utility transfers its generation assets to an affiliate, how should the UDCs recover the cost of power purchased from that affiliate?

A. Staff does not believe that consumers should lose the cost benefits of generation assets simply because those assets are transferred to an affiliate. To that end, Staff recommends that if a utility chooses to transfer its generation assets to an affiliate, purchases of power from the affiliate by the UDC should be subject to an enhanced prudence review by the Commission. Specifically, the prudence of purchases by the UDC from any of its affiliates or from any other wholesale provider should be evaluated based on (1) the costs of other competitive alternatives and (2) the costs the UDC would have borne had the transfer of assets not happened. That is, the established cost of service for the transferred assets should be used as the baseline for evaluating the prudence of power purchases by the UDC from its affiliates and other suppliers.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

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DIRECT

TESTIMONY

OF

JERRY D. SMITH

ELECTRIC UTILIES ENGINEER

UTILITIES DIVISION

May 29, 2002

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EXHIBITS

INTRODUCTION

Q. Please state your name and business address.

A. Jerry D. Smith, 1200 West Washington, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") as an Electric Utilities Engineer for the Utilities Division.

Q. Please summarize your educational background.

A. I graduated from the University of New Mexico in 1968 with a Bachelor of Science degree in Electrical Engineering. I received a Masters of Science degree in Electrical Engineering from New Mexico State University in 1977 majoring in power systems and electric utility management.

Q. Do you hold any special licenses or certificates?

A. I am licensed with the State of Arizona as a Professional Engineer - Electrical.

Q. Please describe pertinent work experience.

A. I joined the Commission Staff in February 1999, following a lengthy career with the Salt River Project ("SRP"), one of the state's largest electric utilities. During my SRP career I:

1. analyzed and planned transmission and distribution system improvements;
2. managed design services required for retail customer projects; and
3. served as primary contact for local municipalities regarding siting of facilities and utilizing funds for aesthetic treatment of water and power facilities.

While employed by SRP, I also performed ancillary functions such as development and management of capital improvement budgets; formation and modification of system planning, operational and maintenance policies, procedures and practices; and creation, modification and administration of new contribution in aid of construction charges and tariffs.

My responsibilities with the Commission have included involvement in Arizona's regulatory rulemaking and rate processes regarding retail electric competition. I have actively participated in the organizational development of an Arizona Independent Scheduling Administrator ("AzISA") and a Regional Transmission Organization ("RTO") called Desert STAR. Desert STAR has since been replaced by a different RTO organizational form and filed with FERC as Westconnect. I was also responsible for the Commission's investigation of distributed generation and interconnections for potential rulemaking consideration.

My experience with the Commission includes providing analysis and testimony regarding quality of service issues, utility planning and siting requirements, system adequacy assessments and cost of service studies. I have also been the Commission's primary staff witness for recent power plant and transmission line siting cases.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before this Commission regarding numerous matters. I have given testimony regarding rate cases, quality of service cases, power plant and transmission line siting cases and I have filed direct testimony regarding the Arizona Public Service Company ("APS") request for variance to ACC Rule 14-2-1606.B in Docket No. E-01345A-01-0822.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in these proceedings?

A. My testimony documents the status of existing and emerging electric system infrastructure in Arizona. I will first address the adequacy of Arizona's existing electric system to ensure reliable electric service to Arizona amidst a competitive wholesale market. Secondly, I will address to what degree emerging new power plants and new transmission lines resolve Staff's system reliability concerns and effectively support the development of a robust competitive wholesale market in Arizona. My testimony will also identify some prevailing risks and operational uncertainties related to Arizona's utility infrastructure. I will conclude with a discussion of the role of Arizona's transmission system in restructuring of the electric utility industry.

Q. How have you prepared for your testimony?

A. I have reviewed information on file with the Commission in the form of annual utility operational presentations, data gathered in the Commission's first Biennial Transmission Assessment, and recently filed ten-year transmission plans. I have also reviewed evidentiary records of power plant and transmission line siting cases. In addition I have reviewed data requests, the Staff Report and evidentiary records filed in the Commission's restructuring docket, and the related APS and Tucson Electric Power Company ("TEP") variance cases (Docket Nos. E-01345A-01-0822 and E-01933A-02-0069).

Q. What conclusions does your testimony reach?

A. A summary of my testimony is reflected in the following general conclusions and recommendations. Staff has concluded that generation and transmission in Arizona is presently inadequate to ensure reliable service to the consumers of Arizona. Utilities are presently dependent upon use of reliability must-run generation and load tripping schemes to meet local load requirements due to local transmission import constraints. Transmission and natural gas pipeline capacity also pose barriers to development of a competitive supply margin with new generators.

Adequate generation is developing in Arizona which may establish a competitive supply margin once transmission reliability constraints are resolved and new gas pipeline capacity is constructed. New transmission solutions are beginning to emerge in the ten-year plans being filed with the Commission. However, considerably more planning is required to ensure sufficient transmission is in place to provide reliable service to Arizona at just and reasonable rates via a competitive wholesale market.

Staff recommends a variety of actions in this testimony. These actions are collectively intended to accelerate development of transmission solutions in Arizona for reliability purposes. These recommendations will also facilitate restructuring of the electric industry to reliably serve consumers at just and reasonable rates via a competitive wholesale market at the earliest possible date. Staff's recommendations include an industry-wide collaborative planning process engaging all sectors of the electric utility industry to resolve local transmission import constraints and transmission constraints prevailing at plant interconnections with the transmission grid.

ADEQUACY OF ARIZONA'S ELECTRIC SYSTEM

Q. Is Arizona's existing electric system adequate to ensure reliable service via a competitive market?

A. Staff is of the opinion that Arizona's electric system in 2002 is currently inadequate to ensure reliable service via a competitive wholesale market. At present, the West's existing wholesale power supply margin is thin and Arizona transmission constraints limit delivery from some new Arizona power plants. Nevertheless, Staff believes the number of Arizona power plants and transmission projects planned and under construction will establish a marginally reliable electric system with an Arizona supply margin of sufficient capacity to facilitate emergence of a competitive wholesale market in Arizona within the next few years.

Q. Please cite any evidence that a thin wholesale market currently exists?

A. APS and TEP provided evidence that a thin wholesale market currently exists during a February 16, 2001, ACC Energy Workshop 2001 - 2002. APS presented its load forecast and expected generating resources as depicted by Exhibits JS-1 and JS-2. Concerns at the workshop focused on the fact that APS was taking extraordinary measures to develop adequate resources for 2001 and 2002 due to inadequacies of the wholesale market in the Western Interconnection ("WI"). Such measures included upgrades to existing APS combined cycle and combustion turbine units, reactivating mothballed APS steam turbine units at West Phoenix Power Plant, and Pinnacle West Energy Corporation ("PWEC") placing 99 megawatts ("MW") of temporary small combustion turbine units at both the West Phoenix and Saguaro plant sites. In addition, the APS resource plan depended on energy from new PWEC combined cycle units at West Phoenix in 2001and at Redhawk in 2002.

TEP loads and resources information for 2002 presented at the February 16, 2001 ACC Energy Workshop is provided as Exhibit JS-3 and JS-4. TEP constructed two combustion turbine units in 2001 with an aggregate capacity of 100 MWs. The new peaking units are located internal to TEP's local transmission system and increased TEP's total generating capacity to approximately 2000 MWs. TEP's total peak demand is projected to be approximately 1990 MWs in 2002 of which 1830 MWs is retail load. TEP's reserve requirement significantly exceeds the 10 MWs differential between its generating capacity and total demand in 2002. Therefore, TEP is dependent upon a firm purchase of 110 MWs from Southern California Edison and 50 MWs of summer peak contingency purchase to meet its 2002 peak demand and reserve requirements.

Q. **Is the natural gas pipeline infrastructure adequate to support existing and all new gas-fired generation plants?**

A. Staff has consistently testified during power plant siting hearings that the existing natural gas infrastructure serving Arizona is inadequate. The natural gas infrastructure in Arizona at this time largely consists of El Paso Natural Gas Company's ("El Paso") northern and southern interstate pipeline systems and associated laterals. The Transwestern pipeline in northern Arizona also serves a small amount of Arizona's natural gas needs. Currently there are no appreciable instate natural gas production, natural gas storage, or liquid natural gas facilities in Arizona. Therefore, natural gas consumers in Arizona, whether residential or power generating in nature, rely on the on-going flow of natural gas on the interstate pipeline system to meet their service needs.

There is a growing uncertainty regarding pipeline capacity available for shippers on the El Paso pipeline system. The rights, obligations, and needs of shippers and El Paso are being disputed in a number of proceedings at the Federal Energy Regulatory Commission ("FERC"). It is unclear how or when the disputes regarding pipeline capacity will be resolved. However, it is clear that during periods of high demand, the El Paso system is unable to fully meet the needs of its existing shippers. During periods of relatively low demand on the interstate pipeline system, it appears that the system is generally able to meet the current needs of its shippers. This situation exists at a time when few of the new natural gas-fired generating units in Arizona or New Mexico are operational. As additional natural gas-fired generating units come on line in Arizona and other southwestern states utilizing the same pipeline systems, the inability of the existing pipeline system to serve all customer demands will become increasingly apparent.

Q. Are there transmission constraints inside or outside Arizona that currently impede wholesale market access to Arizona customers during any seasons of the year or times of the day?

A. Yes, significant transmission constraints around Arizona's major load centers are another factor contributing to the thinness of the wholesale market in Arizona. Transmission constraints both inside and outside Arizona currently impede energy from the wholesale market from reaching Arizona customers during summer peak hours. These constraints were reported in Staff's Biennial Transmission Assessment revised July 2001 and adopted by the Commission. The report established that three geographical load zones (Phoenix, Tucson and Yuma) are transmission import constrained at peak load conditions. These transmission import constrained geographical load zones are depicted in Exhibit JS-5 and are dependent upon local reliability must-run ("RMR") generation.

Two additional transmission constraints have been identified since Staff's Biennial Transmission Assessment was completed. Toltec Power Plant siting hearings (Case #112) revealed that the new Reliant Desert Basin Power Plant in Casa Grande could not deliver its full capacity to SRP in the Phoenix area because of 115 kV and 230 kV transmission system constraints between the plant and the Phoenix load zone. Testimony during Case #111 siting a TEP 345 kV transmission line and Citizens Communications 115 kV transmission line to serve Nogales and Santa Cruz County revealed another transmission constraint. Citizens Communications presented a load forecast that indicated that as early as summer peak 2003 the load in Santa Cruz County may exceed the delivery capability of the existing 115 kV line serving the area. Even with the proposed new transmission line to Nogales, continuity of service to customers is of concern in case of the outage of the new line.

Similarly, new generation capacity under construction and interconnecting at the Palo Verde commercial hub will be constrained by existing 500 kV transmission lines interconnected at the hub. The Biennial Transmission Assessment references Palo Verde Interconnection Studies that have shown that no more than 1,800 to 3,360 MWs of new generation can be accommodated at the Palo Verde hub without transmission upgrades. This capacity is over and above the transmission capacity committed to the Palo Verde nuclear generating units. Four generating projects totaling 3,930 MWs are currently under construction and will be interconnected at the Palo Verde hub over the next 12 months. Two of the projects totaling 1,640 MWs are expected to be operational this summer.

Q. How does reliability must-run ("RMR") generation relate to transmission reliability?

A. Generation existing within a local system can be operated to serve load that would otherwise be served by the importing transmission system. However, when the load being served by a transmission system exceeds the system's transmission import capacity, the system is said to be reliability constrained. Generation internal to such reliability constrained load zones "must run" at sufficient capacity to avoid system overloads and voltage problems for outage of critical lines. Generating units operated for this purpose are called reliability must-run ("RMR") units during the period for which the transmission constraint exists.

Utilities have traditionally used RMR generating strategies as an operational safety net when siting or construction of new transmission facilities was impeded, delivery of new equipment was delayed, capital financing was constrained or to restore service following a transmission outage. Utilizing RMR generation to defer capital investment in reliability enhancements in a utility's transmission system may also have merit when:

1. The total operating cost of local must-run generators is less than that of generators external to the constraint and the avoided annual cost of the deferred capital investment in new transmission facilities,
2. Environmental standards are not compromised and
3. Such action does not pose unacceptable system service risks.

A transmission system is considered reliable when it is of sufficient capacity to deliver its power (demand and energy) at all times without interruption of service to its customers for loss of any single transmission system element. Annual dependency on RMR generation can be an indicator that a transmission system's import capacity is inadequate. This is particularly true when must-run generation costs are simply passed through the regulatory rate base without balancing in the public's interest the reliability, economics and environmental merits of investments in additional transmission capacity to provide access to less costly or more environmentally friendly generation external to the constraint.

Q. What evidence can you provide relative to APS' and TEP's dependency on RMR generation for the Yuma, Phoenix and Tucson transmission import constrained load zones?

A. Mr. Cary Deise of APS gave rebuttal testimony regarding the Yuma area in the APS variance request case.[1] He described how Yuma transmission import constraints have ebbed and flowed over time as local load growth occurred. As Yuma load grew it would reach a point where it exceeded the transmission system's import capability. RMR generation would then be utilized and such requirements would increase in both duration and capacity over time as load continued to grow. New infrastructure was constructed when the Yuma area load was projected to exceed the combined load serving capability of its transmission system and local generation.

Both new transmission lines and new local generation have been constructed at various points in time to enhance APS' Yuma load serving capability. Such infrastructure improvements were selected based upon economic choices driven by consideration of APS' broader integrated resource planning needs. When new system generation was needed and it could be located in Yuma so as to avoid the need to also build a transmission line to Yuma it was logical to do so. When APS' generating capacity was adequate then transmission was constructed. Therefore, Yuma's RMR generation requirements have gone through cycles of increasing to the point of requiring either new local generation or a new line. Then for a period of years the transmission constraint was mitigated and RMR generation requirements were either retracted or diminished in both duration and capacity.

Restructuring of the electric industry may result in a Utility Distribution Company ("UDC") not having the same planning choices for infrastructure as an integrated utility. If a UDC transfers all of its generation assets and secures all of its resource requirements

[1] Rebuttal Testimony of Cary Deise, APS Request for Variance to Certain Requirements of A.A.C. R14-2-1606, April 22, 2002, pages 7-10.

from a competitive market, it may not be able to depend on the power plant industry locating or timing construction of new generation to minimize the UDC's transmission expansion requirements. Therefore, the traditional planning practices of vertically integrated utilities cited by Mr. Deise[2] may no longer be applicable. Considerable industry discussion is ongoing in an effort to define how coordinated and collaborative planning can best take place in the West. Such planning in Arizona is evolving in a way so as to consider the collective needs of the Arizona transmission providers and independent power producers.

The UDC is no longer in the business of constructing generation but remains responsible for assuring that its customers continue to have access to just and reasonably priced energy via a reliable transmission system. Nevertheless, dependence upon existing local generation for RMR purposes may continue to afford a transmission provider an operational safety net and facilitate the deferral of costly transmission improvements under favorable wholesale market prices and environmental conditions.

Mr. Deise provided an exhibit documenting the APS Phoenix area RMR requirements in his rebuttal testimony in the APS request for variance case.[3] His data assumes the Palo Verde to Southwest Valley 500 kV line will be successfully constructed by the Summer of 2003 thereby raising the APS transmission import capacity by 600 MWs to 3,685 MWs. With a total of 3,685 MWs of transmission import capability Mr. Deise reveals that APS' RMR generation requirements for the Phoenix area will grow from 427 MWs in 2003 to 1,034 MWs by 2007. A segment of Mr. Deise's data is presented in the following table.

[2] Ibid., at page 9.

[3] Rebuttal Testimony of Cary Deise, APS Request for Variance to Certain Requirements of A.A.C. R14-2-1606, April 22, 2002, Schedule CD-3R.

Table 1.

Year	APS Valley Load (MW)	APS Import Capability (MW)	APS RMR Gen. Requirement (MW)
2003	4112	3685	427
2004	4256	3685	571
2005	4405	3685	720
2006	4559	3685	874
2007	4719	3685	1034

Exhibit JS-6 was presented as evidence during transmission line siting Case #115 and depicts APS' capability to serve load within the Phoenix transmission constrained area. It demonstrates APS' dependency upon existing units and new PWEC units to meet its RMR requirements. It is important to note that a Phoenix area load tripping scheme was implemented by APS and SRP for the 2001 summer peak season. The load tripping scheme will continue through the 2002 summer peak season and until construction of the Palo Verde to Southwest Valley 500 kV line is completed. This scheme is necessary to avoid critical single contingency line outages or generator outages causing protection and control systems to interrupt other electric facilities. Such cascading events would not be in compliance with Western Electricity Coordinating Council ("WECC") reliability criteria.

TEP provided Staff an update regarding its Tucson transmission import capability and associated RMR generation requirements in response to a data request in this case. A portion of that data is displayed in Table 2. The Tucson transmission import limit is expected to increase by approximately 200 MWs in 2003 due to the planned construction of a second Saguaro to Tortolito 500 kV tie and transformer. For load and resource planning purposes TEP has utilized 1,535 MWs as its import limit. TEP's local area peak demand grows from 1,889 MWs in 2003 to 2,099 MWs in 2007. Therefore TEP's RMR requirement grows from 354 MWs to 564 MWs over the same time period. TEP's total local generation capability is 640 MWs through 2007. This leaves a local supply margin of only 76 MWs in 2007.

Table 2.

Year	TEP Tucson Load (MW)	TEP Import Capability (MW)	TEP RMR Gen. Requirement (MW)
2003	1899	1535	364
2004	2001	1535	466
2005	2025	1535	490
2006	2082	1535	547
2007	2099	1535	564

Staff is of the opinion that UDCs have a responsibility to demonstrate the merits of continuing or increasing their dependence upon local RMR generation. Is continuing to depend on RMR generation in consumers' best interest and does it economically justify deferral of transmission improvements that would resolve transmission reliability constraints? Neither APS nor TEP has provided such an assessment to Staff. Staff offers a recommendation in this testimony that the Commission require all jurisdictional utilities utilizing RMR for their load requirements to provide Staff with such an analysis.

In the meantime, Staff has performed an assessment contrasting the annual cost of RMR generation with the avoided annual cost of a new EHV transmission line. Exhibit JS-7 offers a demonstration of when the economics of RMR generation appears to justify deferral of EHV transmission investment. The formulas, definition of terms and assumptions of parameters used in this analysis are provided as Exhibit JS-8. The cost of RMR energy produced during a constraint period of 400 hours has been plotted as a function of the peak RMR generation requirement. A solid line depicts that cost for each of four generic generating units. The unit operating cost ranges from $50/MWhr to $150/MWhr. Similarly, the annual avoided cost of an EHV transmission line investment has been plotted as a function of line length. A dashed line depicts the avoided annual cost of EHV lines of lengths 50, 100 and 150 miles. A breakeven point exists where solid lines intersect dashed lines. Economics favor transmission line construction when the actual cost of RMR exceeds the annual avoided cost of such line construction.

One can conclude from Exhibit JS-7 that generally an EHV transmission line 50 miles in length or greater is economically justified when the RMR generating unit hourly operating cost is $75/MWhr or greater and when the RMR requirement is greater than 400 MW. APS' and TEP's RMR generation requirements documented in Tables 1 and 2 generally exceed the 400 MW identified by the above conclusion by several hundred MWs. Staff believes that the hourly operating cost of APS and TEP RMR units used at peak are in excess of the $75/MW value referenced in the above conclusion. Therefore, Staff believes APS and TEP may find it difficult to economically justify deferral of transmission improvements given the magnitude and duration of RMR generation utilized and actual total operating cost of their local generators.

EFFECT OF NEW INFRASTRUCTURE

Q. Staff suggested in its power plant update to the Commission that a competitive supply margin is necessary for a competitive market to flourish. What is Staff's definition of "competitive supply margin?"

A. Staff believes a "competitive supply margin" exists for any given area when generation capacity within that area exceeds load, net export obligations and reserve requirements of that area by an amount sufficient to result in competitive pricing among the generators within that area. Refer to Exhibit JS-9 for a visual depiction of this concept. This model assumes all generators in the area are available to compete for wholesale market services and are not constrained by transmission capacity. This definition of supply margin is consistent with FERC's use of the term in its pivotal test for market power. Mr. Schlissel has provided testimony in this case that explores to what degree market power exists in Arizona using this test.[4]

Staff has not ascertained what percentage of supply margin would be necessary to ensure competitive pricing in the local wholesale market. It is Staff's belief that the composition of the area's generation portfolio regarding vintage, types of generating technology, and fuel sources would have a significant bearing on the competitive supply margin appropriate for a given area. In addition, there are known local transmission constraints that may inhibit just and reasonably rates via competitive generation pricing from being realized in the local market in the short-term.

Q. Is a competitive supply margin emerging in Arizona?

A. It is Staff's opinion that an adequate supply margin is emerging in Arizona. However, the determination of how competitive that supply margin will be is still yet to be determined. It does not matter how many new plants are constructed and competing if the transmission system is not sufficient to deliver the power from these plants to the intended load centers. Local transmission constraints may be a barrier to effective competition of new generators entering the Arizona wholesale market. Mr. Schlissel has provided testimony in this case regarding how transmission plays a role in market power concerns for an emerging competitive wholesale market. Once local transmission constraints are resolved, it is Staff's opinion that the number of new generators constructing or planning to construct in Arizona will be of sufficient number and capacity to result in a competitive supply margin in this state. Such a competitive supply margin may not be fully realized in Arizona until the last half of this decade.

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[4] Direct Testimony of David A. Schlissel, Docket No. E-00000A-02-0051, pages 4-8.

The Biennial Transmission Assessment documented that 22 plants located in Arizona existed in 2000 with an Arizona utility owned capacity of 11,724 MWs. The actual 2000 summer peak load in Arizona served by those same units was approximately 13,000 MWs. Arizona has in recent years been progressively more dependent upon import of supply from other states at peak load conditions.

Exhibit JS-10 depicts the status of new proposed power plants in Arizona. We are quickly moving towards an adequate supply margin in Arizona with 1,830 MWs of new generation that became operational in 2001 and 7,210 MWs of new generation under construction that is planned for operation by Summer 2003. An additional 5,180 MWs of new generation has obtained ACC approval of a Certificate of Environmental Compatibility and is scheduled to come on line between 2003 and 2007. These new generating units total 14,220 MWs of new generation in Arizona.

In the same time period Arizona's peak load will grow at approximately 600-700 MWs per year. This would yield an Arizona peak load in 2007 of approximately 18,000 MWs, a 5,000 MW load growth from the year 2000 peak. The implications are that Arizona generation expansion will likely occur at a three to one ratio compared to Arizona load growth. This bodes well for establishing a robust supply margin in Arizona and allows Arizona to contribute substantially to the supply needs of the Western Interconnection.

However, the transmission and natural gas supply problems discussed elsewhere in my testimony may impede the development of competition in the wholesale market in spite of the emerging supply margin.

Q. What plans are in place to relieve transmission constraints?

A. APS has planned a new 230 kV line from Gila Bend to Yuma by 2006. This line will eliminate the transmission import constraint for the Yuma area. In addition, York and

Welton Mohawk Irrigation and Drainage District have proposed a new Yuma area generation project for 2004. The generation project is active in the state siting process as Case #114.

A new 500 kV line from the Palo Verde hub to the new Southwest Valley switching station has been approved in Line Siting Case #115. That line is under construction for a Summer 2003 completion. It will help mitigate the Phoenix import constraint and lessen the dependence on local RMR generation. During the past year, two additional 500 kV transmission lines have been announced for 2006 and 2008 that will help relieve the transmission import constraint for this area: a Palo Verde to Southeast Valley Switching Station line and a Palo Verde to Table Mesa line.

PWEC is a partner in expanding generation at the West Phoenix Power Plant. Similarly, SRP is expanding its Kyrene Power Plant and Santan Power Plant. All three power plant projects are internal to the transmission import constrained Phoenix load zone. These new plants may compete with other new merchant plants developing in Arizona and will operate under more stringent environmental standards than existing local units.

TEP is proposing to construct a second 500 kV transmission line and transformer between Saguaro and Tortolito Substations by summer of 2003. This project increases the Tucson import capacity by approximately 200 MWs. TEP's proposed 345 kV transmission line interconnecting with Mexico will likely improve TEP's import capability to its Tucson service area. Several other new transmission line alternatives are still being evaluated in the Central Arizona Transmission Study ("CATS") that will relieve the Tucson import constraint.

In addition to the three new Palo Verde transmission lines identified above, the Commission has conditioned Duke's Arlington Valley II Power Plant with the upgrade of the Palo Verde to Kyrene and Palo Verde to North Gila 500 kV lines. A number of other

Palo Verde line projects have been discussed but applications for Certificates of Environmental Compatibility ("CEC") have not yet been filed with the Commission. Public Service Company of New Mexico ("PNM") still has a transmission line from Palo Verde to Mexico under study through CATS. The PNM line is active in a federal Environmental Impact Study("EIS") and Presidential Permit process with the US Department of Energy as the lead agency. There has been recent discussion of upgrading the existing Palo Verde to Devers line and building a second Palo Verde to Devers 500 kV line. Similarly, a merchant transmission project to build a 500 kV line from Gila Bend to North Gila in conjunction with other transmission enhancements in California continues to seek a funding source.

Q. Is it certain that all of these transmission projects will be built?

A. There remains some risk of public opposition to new transmission lines planned for construction in the short-term. The same risks would exist for any other presently unidentified transmission lines required to keep pace with forecasted load growth or eliminate RMR generation requirements. Some of the longer-term transmission improvements remain very speculative and lack any definitive funding sponsor, specific scope or well-defined in-service date. I speak to the uncertainties and risks of such projects in the next section of my testimony.

PREVAILING RISKS AND UNCERTAINTIES

Q. What electric supply risks and uncertainties is Arizona likely to face?

A. Even though APS has taken extraordinary steps with its affiliate to develop its own short-term resource solutions, it remains vulnerable to short-term contracts in a tight wholesale market.[5] The short-term wholesale market in the West is faced with continued market price caps, on-going California supply deficiencies, and natural gas supply and delivery concerns. These concerns were borne out in the summer of 2001. Precautionary steps were taken by Arizona utilities when the natural gas industry announced pending gas

[5] See this testimony, page 5.

curtailments. Furthermore, on July 4, 2001, APS was within one half hour of activating rolling blackout procedures due to unavailability of several generating units due to repairs and the subsequent outage of the Saguaro Power Plant due to a lightning storm. Rolling blackouts were avoided when APS successfully obtained emergency short-term purchases from its neighboring utility, the Salt River Project.

Four new merchant power plants have begun commercial operations since the February 16, 2001, Energy Workshops. A technical summary of the four plants is provided as Exhibit JS-11. The total nominal capacity of these plants is 1,830 MWs. The Griffith Power Plant and South Point Power Plant are located in Mohave County. The new PWEC combined cycle plant is located at the APS West Phoenix power plant site. Reliant's Desert Basin plant is located in Casa Grande. Each new plant has faced difficulties becoming operational over the past year. Operational testing and FERC exempt wholesale generator certification challenges normally encountered by new power plants have also been accompanied by transmission concerns for several of the new plants.

Numerous power plants under construction and listed in Exhibit JS-12 lack certainty regarding their commercial in-service date. Pipeline capacity and associated contractual rights to deliver natural gas to fuel existing and new power plants is also questionable. Similarly, potential delays in rights of way procurement or legal challenges of construction authority granted via Commission approved Certificates of Environmental Compatibility could lead to uncertainty regarding the operational date of proposed new transmission lines proposed for service in 2003. Supply from new generation in Arizona is dependent upon the favorable resolution of each of these risks and uncertainties.

Q. What risks and uncertainties are associated with natural gas supply and delivery?

A. El Paso Natural Gas Company has failed to address the growing demands for natural gas transportation in Arizona and the Southwest. New generating facilities appear to be relying on a number of possible sources of pipeline capacity for their facilities, including:

use of existing contract rights, acquiring released pipeline capacity from other shippers, purchasing rights on new pipelines or pipeline expansions, and swapping of gas supplies on different pipeline systems.

In the long term, market players are likely to build additional pipeline capacity and/or natural gas storage capacity to serve additional demand for natural gas in Arizona and the Southwest. Exhibit JS-13 depicts two gas pipeline projects and a gas storage facility that have been announced for Arizona. However, it is unclear at this time how well the availability of additional pipeline capacity in the future will coincide with the additional natural gas demand of the new generating facilities in the next few years. The on-going uncertainty regarding existing shippers' rights on the El Paso system has made it difficult for both shippers and potential capacity expansion developers to accurately gauge what the demand/need is for additional capacity. Most new gas-fired generating units in Arizona are located near El Paso's southern pipeline system, and this is likely to be the area of greatest concern regarding the shortfall of interstate pipeline capacity, although several recently announced pipeline projects may at least partially address the shortfall.

Q. How long will it take to relieve any existing transmission constraints and what factors are affecting and will affect prospects for relief?

A. Phoenix-area 500 kV transmission additions increase import capacity by 3,200 MWs in the 2003 through 2008 time period. When this new import capacity is coupled with new power plants and expansions internal to the constrained area, local utilities' dependence upon older, more costly, and higher polluting local generation should be reduced through about 2008. Appropriateness of additional transmission to further mitigate RMR generation requirements during this time period is still to be determined. However, Staff has yet to see transmission solutions proposed for the Phoenix area that will eliminate the transmission import constraints in the long term. Since two of the three new 500 kV lines from Palo Verde must still go through the rigors of a state line siting process, there remains some risk of public opposition for the new lines. The same risks would exist for any other presently unidentified transmission lines required to keep pace with forecasted load growth or eliminate RMR generation requirements.

The Tucson transmission import area faces the same line siting risks as the Phoenix area. In fact the environmental community and public at large have already been very vocal regarding a variety of transmission projects in Central and Southern Arizona. Nevertheless, there appear to be sufficient transmission options under investigation to resolve the Tucson import constraint within the next few years.

The Yuma transmission import constrained area appears to have several competing line solutions moving forward towards a 2004 resolution. New proposed merchant generation in the local area may also offer Yuma a remedy as early as 2004. It is premature to judge how quickly the Nogales constrained area will be resolved until Citizens Communications identifies its proposed solution.

Resolution of transmission constraints at the Palo Verde hub are the most difficult to project. Except for the new 500 kV lines proposed by Arizona transmission providers, all other transmission improvements remain very speculative and lack any definitive funding sponsor, specific scope or well-defined in-service date. Most of these proposed 500 kV transmission projects improving the Arizona / California transfer capability will require Arizona line siting approval. At best, these projects are likely to formally emerge in the last half of this decade.

ROLE OF TRANSMISSION IN ELECTRIC RESTRUCTURING

Q. What role does Arizona transmission play in the restructuring of the electric utility industry?

A. The transmission system plays a vital role in the restructuring of the electric utility industry. Transmission systems constructed to deliver power from specific resources to specific load centers already exhibit both local and regional reliability constraints. These constraints are presently resolved operationally by established congestion management techniques such as commitment of RMR generation units, generation re-dispatch, schedule curtailments, and finally voluntary or involuntary load curtailments. These measures are taken to relieve reliability constraints with little regard for the commercial effects on the industry.

It is reasonable to presume that the same transmission system will likely exhibit even greater constraints or barriers to delivery from alternative power plants to the same load center, delivery from the same power plants to different load centers or delivery from newly interconnected power plants to undetermined load centers. This is particularly true in the West because of the unique topology of the transmission system and the general sparsity of the interconnected EHV transmission system and local transmission networks. This presumption is based purely on the laws of physics rather than any market pricing or economic principles.

Timely construction of new infrastructure resolving prevailing and yet to be discovered transmission reliability constraints is paramount to ensuring that the UDC's consumers continue to benefit from reliable service at just and reasonable rates. Transmission enhancements are also a prerequisite for emergence of a reliable and economically viable competitive wholesale market. Interconnecting new generation projects without considering the transmission system necessary to reliably deliver the merchant's commodity to a market is simply commercial folly. Merchant plants certainly have the right to take such commercial risks. However, interconnection of such plants to the grid without a demonstration of the ability to reliably deliver to a market can result in placing the entire Western grid at operational risk. Staff also contends that new generation located on the load serving side of a transmission constraint is a reasonable alternative to new transmission if such projects:

1. are constructed early enough to allow the transmission provider certainty of compliance with WECC and local reliability criteria,

2. willingly commit to a "reliability must-offer" arrangement when capacity is not already utilized. Such arrangements should be void of market pricing greater than that prevailing external to the constraint,
3. do not unduly compromise local environmental standards, and
4. pose no unreasonable service risks such as fuel supplies subject to curtailments or price uncertainty.

Otherwise it would be prudent for the UDC to proceed with construction of appropriate transmission facilities.

Q. Are transmission owners currently doing things that will allow them to exert more or less control in the future? If so, please detail.

A. It is Staff's opinion that Arizona transmission owners have over the past year made significant progress in planning and announcing new transmission additions to resolve local transmission import constraints and mitigate perceived transmission market power within Arizona. While it will take a number of years for these new lines to be sited and constructed, there has certainly been a good faith demonstration by Arizona utilities of their commitment to respond favorably on a forward looking basis. The recent transition from a Desert STAR RTO to a WestConnect RTO is also reflective of a commitment to have an RTO with the authority to build transmission lines if others do not.

Q. Will the transmission system be adequate prospectively (e.g., in the next 5, 10, 15, 20 years) to deliver power from new generation plants?

A. Based upon a preliminary review of all transmission plans approved with a CEC and those filed with the Commission, Staff believes Arizona transmission system adequacy for new generating plants will be achieved in the last half of this decade. FERC anticipates that a regional RTO will, in time, be the entity responsible for ensuring the adequacy of transmission capability in the Southwest or West. FERC has suggested that some form of incentive ratemaking could be used to encourage appropriate transmission upgrades identified through an RTO planning process. The process of getting a regional planning and incentive pricing structure in place will likely take several years. The Western Governors' Association ("WGA") has recognized the need to push this agenda on an interim basis.[6] The West simply cannot wait on FERC and RTOs to address this transmission need via market driven solutions.

Staff is not in a position to accurately assess the adequacy of planned transmission system enhancements filed with the Commission as of January 31, 2002. Such an assessment will be rendered upon completion of a second ACC biennial transmission assessment that will likely commence in June. **Nevertheless, Staff believes that accelerated development of transmission solutions beyond that which has been filed with the Commission is needed in order to facilitate restructuring of the electric utility industry to reliably serve Arizona consumers at just and reasonable rates via a competitive wholesale market.** The Commission can ill afford to wait for market failures to drive solutions when our state is dependent upon the new generation developing in Arizona. A proactive approach to resolving Arizona's local transmission needs should be adopted and implemented by the Commission as part of this generic restructuring case.

Q. How has the restructuring electric industry responded to transmission needs in Arizona?

A. Establishing a framework for transmission expansion that retains traditional system reliability-based service values and yet assures consumers are not harmed by others' direct access of the same transmission system for competitive wholesale market transactions is a challenge. One must first recognize the diversity of regulatory objectives regarding restructuring and associated layers of evolving jurisdictional authority. Secondly, business objects of different sectors of the restructuring industry are counter-poised and in conflict. This is most evident by the tug of war being exercised by parties in this case.

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[6] WGA's August 2001 "Conceptual Plans for Electricity Transmission in the West" report.

Staff does not profess to have the magical answer that can resolve the chaos of electric restructuring. However, Staff believes that an industry-wide need exists for the timely development and construction of necessary transmission enhancements to mitigate reliability concerns. Consumers need assurances that the UDC will not abandon its obligation to continue providing reliable service at just and reasonable rates. UDCs are uncertain who their energy supplier of the future will be and what transmission is needed to gain access to those resources. Therefore, UDCs are playing the waiting game and deferring transmission investments by relying on RMR generation opportunities. Meanwhile, new merchant power plants and market participants are dependent upon transmission to deliver their commodity to market. However, they too have not predetermined their intended market and therefore are seeking only to interconnect with the grid (or hub) in hopes that whomever wants the power will "come and get it" and make the necessary transmission provisions.

Hence, a game of chicken prevails regarding transmission required to support a competitive wholesale market. Who will be harmed if the game is protracted - the consumer. Deterioration in quality of service and uncontrolled and volatile market pricing of generation and transmission services would be likely outcomes. Fortunately, Arizona's CATS study effort has managed to bring both the transmission providers and interested merchant power plants together in a common forum to look at transmission options that can fulfill the needs of all parties. As a result several transmission lines have been announced and invitations made to all parties interested in participating in the projects. This is a good beginning. Staff's recommendations regarding resolving Arizona's transmission constraints build on this model and engages all affected sectors of the restructuring industry.

Q. What action does Staff recommend to assure timely development and construction of necessary transmission enhancements?

A. Both transmission providers and power plants share the burden and obligation to resolve Arizona transmission constraints. Staff recommends that the Commission adopt the following two reliability standards and require both sectors of the electric industry to work collaboratively to build sufficient Arizona transmission to comply with these reliability standards at the earliest possible date. Staff first recommended these two reliability principles in its Biennial Transmission Assessment.[7]

1. There should be sufficient transmission import capability to reliably serve all loads in a utility's service area without limiting consumer access or benefit to more economical or less polluting generation located external to the service area.
2. A power plant must have sufficient interconnected transmission capacity to reliably deliver its full output without use of remedial action schemes for single contingency (N-1) outages or displacing a priori generation interconnected at the same switchyard or on the same transmission lines.

Staff contends compliance with the above transmission reliability objectives will ensure reliable service to Arizona consumers at just and reasonable rates while providing an opportunity for a competitive Arizona wholesale market to emerge unbridled by local transmission constraints. Staff recommends the Commission approve the following five actions to foster resolution of transmission reliability concerns in a responsible and managed manner.

1. Staff recommends that the Commission order that all sectors of the electric industry affected by existing transmission constraints collaborate in studies to determine the most effective solutions to resolve reliability concerns and agree to support and advance the construction of such projects for service at the earliest possible date.

[7] ACC Staff, Revised Biennial Transmission Assessment 2000-2009, Revised July 2001, page 3.

2. Matt Rowell gave testimony recommending that the Commission order APS and TEP to submit a market power study prior to transfer or divestiture of any generation asset. That market power study should address known Arizona transmission constraints and identify how transferring generating units will impact other market participants uses of transmission services over those constrained paths.
3. Staff recommends that the Commission order jurisdictional utilities to resolve RMR generation concerns by:
    a. Performing and completing, within 30 days of a decision of Track A issues in this docket, a study analyzing the merits of existing dependence on RMR generation rather than building transmission to resolve local transmission import reliability constraints,
    b. Perform a study analyzing the merits of any future contemplated utilization of RMR generation to defer transmission projects, and that
    c. Such RMR study reports be filed with the Commission for review within 30 days of completion of such studies and prior to implementing any new RMR generation strategies.
4. Staff recommends the Commission further order jurisdictional utilities to proceed to resolve any transmission import reliability constraint by constructing needed transmission facilities as soon as practical if the Commission finds their RMR generation strategy to not be in consumers' best interest.
5. Merchant power plants should not be left out in this matter of resolving transmission reliability constraints. Therefore, Staff recommends that the Commission establish the following two standards regarding future power plant applications for a CEC.
    a. Future power plant applications for a CEC should be denied for sufficiency purposes if they have not fulfilled the statutory technical study requirements demonstrating the impact of their project on the existing Arizona transmission system.
    b. Power plants that fail to demonstrate the ability to reliably deliver to a market without displacing a priori generation interconnected at the same location or

utilizing the same interconnected transmission system should not be granted a CEC.

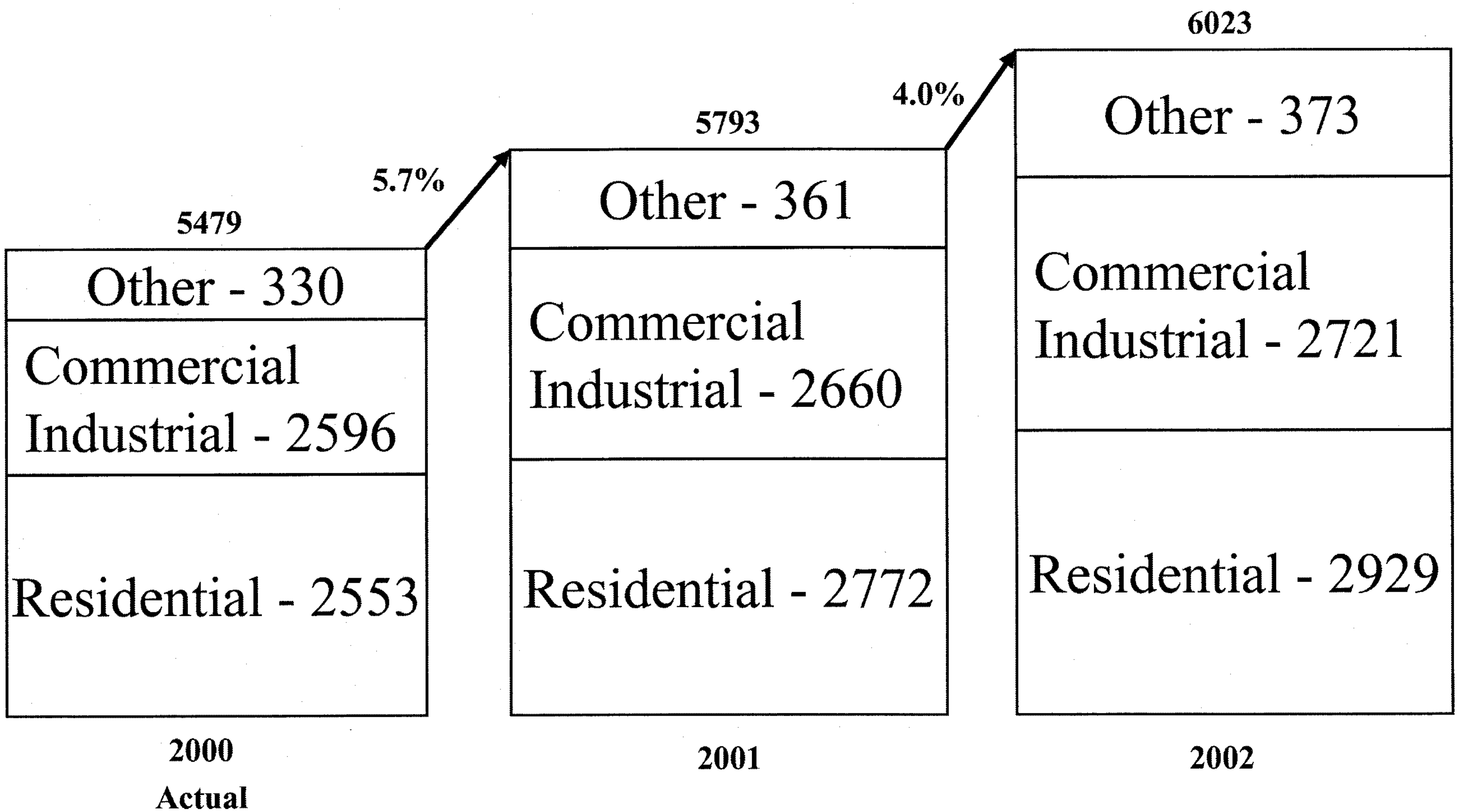
These two standards will encourage new power plants to participate in the collaborative transmission process defined by Staff's first recommended in this testimony.

Q. Does this conclude your testimony?

A. Yes it does. However, Staff requests the right to modify or supplement its testimony to allow alignment and reconciliation with related electric restructuring issues that emerge during future tracks in these proceedings.

EXHIBITS

APS
Peak Load Forecast



Values in MW

Exhibit JS-1

APS Resources

		2001	2002
=	Existing Generation	**3982**	**4497**
	Renewable	**9**	**13**
=	Additions		
	Upgrade of existing CC&CT	**107**	**-**
	Reactivate WPhx Steam 4&6	**96**	**-**
	WPhx CC 4	**114**	**-**
	Temporary WPhx CT's - 5 units	**99**	**(99)**
	Temporary Saguaro CT's - 5 units	**99**	**(99)**
	Redhawk CC 1&2	**-**	**988**
	Subtotal	**515**	**790**
=	Long-term Contracts		
	Pacificorp Exchange	**480**	**480**
	SRP	**336**	**343**
	Subtotal	**816**	**823**
=	Short-term Contracts	**1176**	**638**
=	Total Resources	**6498**	**6761**

Exhibit JS-2

2002
TEP Loads and Resources

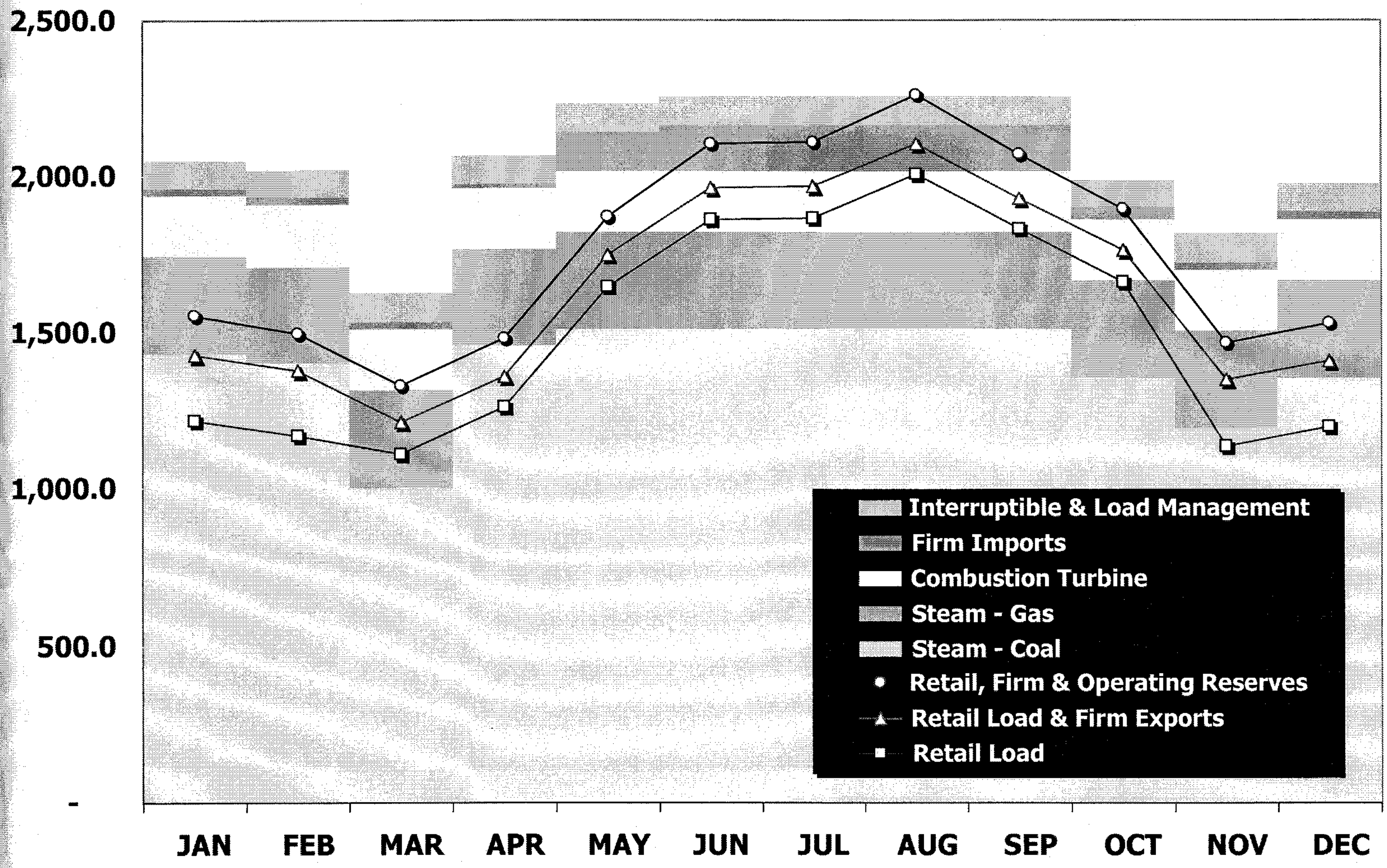


Exhibit JS-3

Generation Capacity

- 1520 MW of Base load Coal
- 255 MW of Intermediate Gas Steam
- 125 MW of Combustion Turbines
- 75 MW new Combustion Turbine (June 1, 2001)
- 25 MW new Combustion Turbine (permitting in progress, May 1, 2001)
- 2000 MW Total Generation Capacity

Note:

TEP receives 110 MW from SCE during summer period

Exhibit JS-4

Arizona EHV Transmission

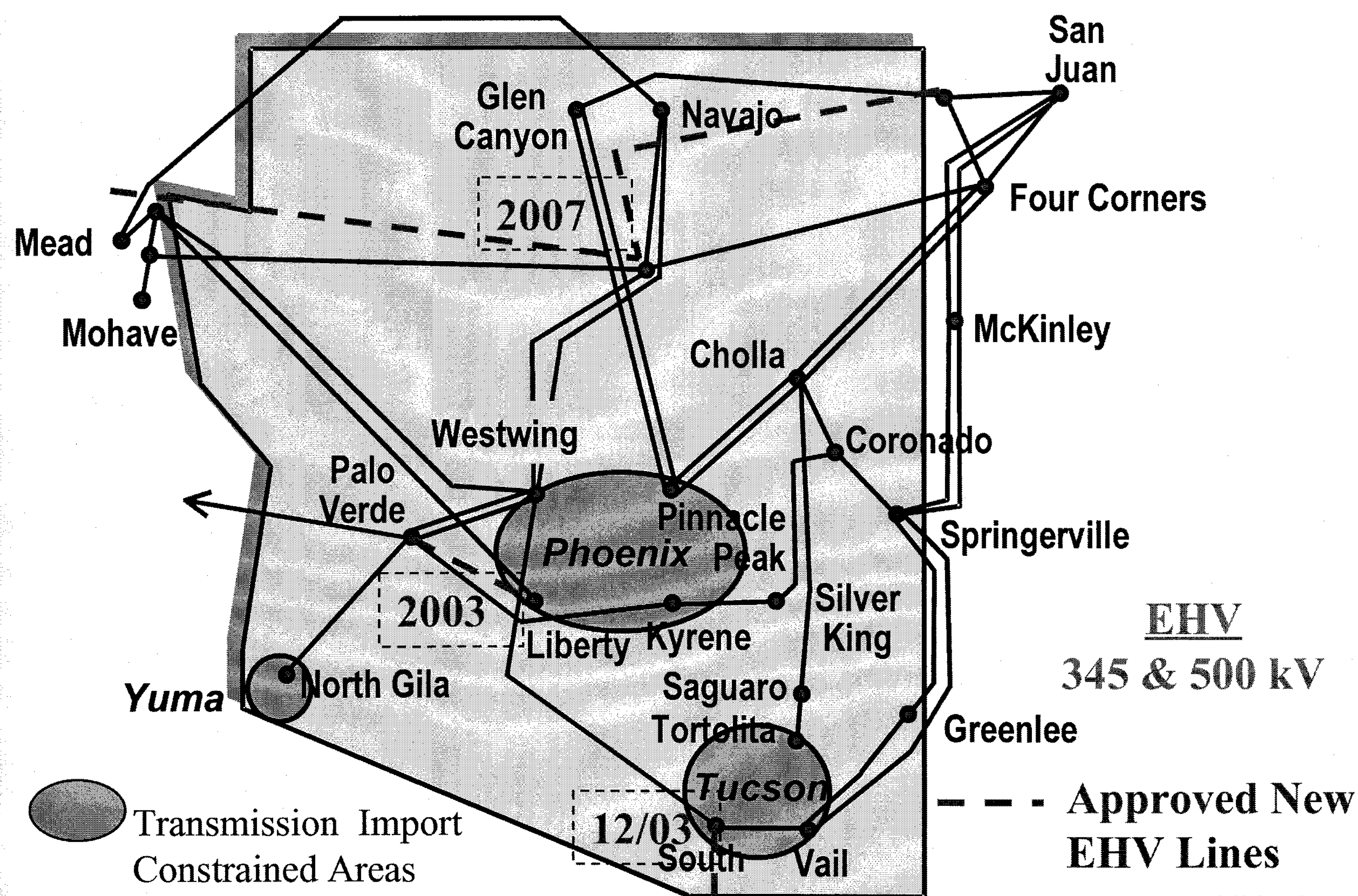


Exhibit JS-5

Case #115

Recreated in Excel using Exhibit D - 12

Districts' Second Revision Figure 14 from the Revised Biennial Transmission Assessment

APS Phoenix Metopolitan Area Load Serving Capability

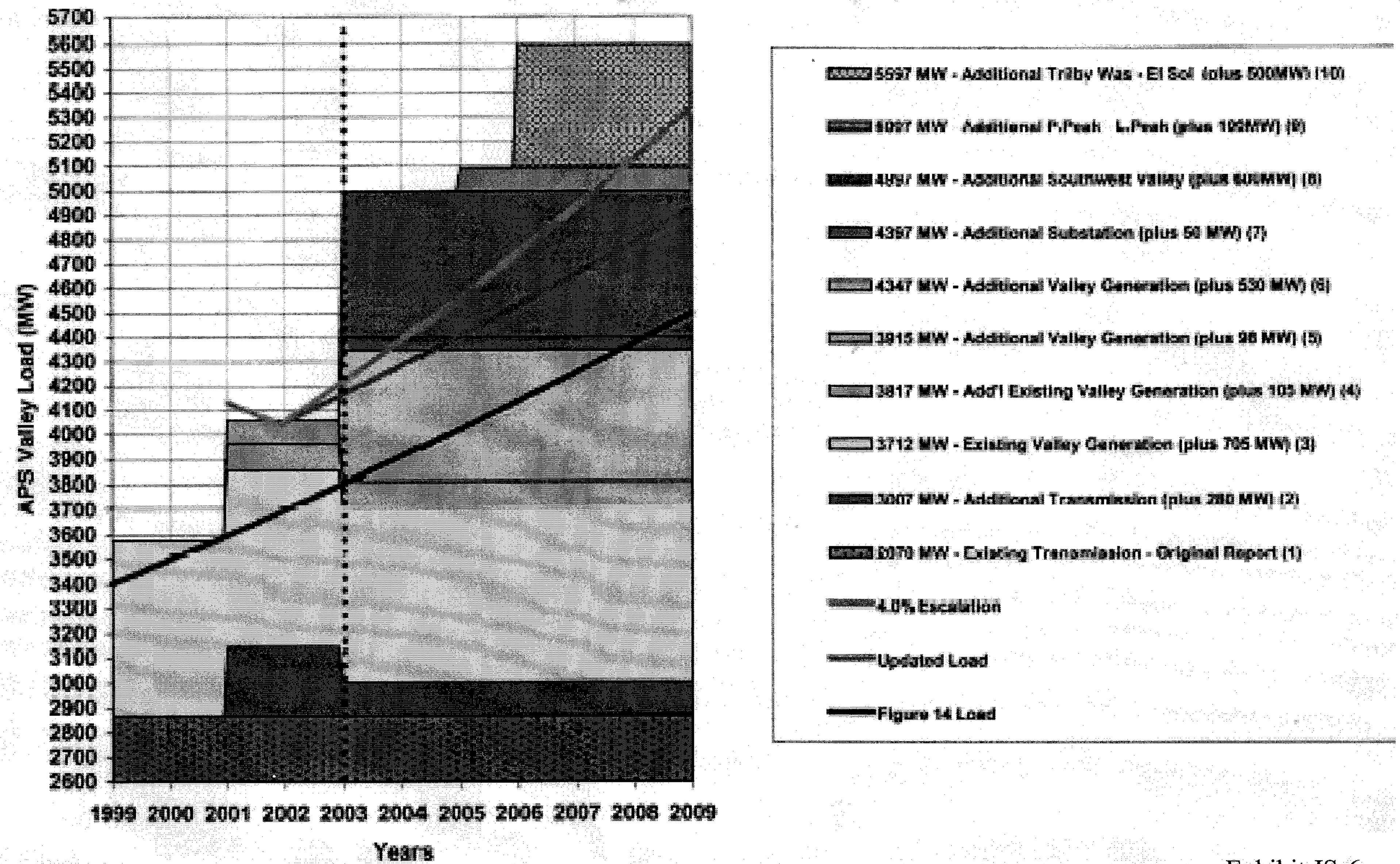


Exhibit JS-6

RMR Generation vs Transmission

RMR is economically prudent when $C_{rmr} \leq C_a$

where C_{rmr} = Cost of reliability must-run energy during the constraint period and
C_a = Annual avoided cost of transmission line investment

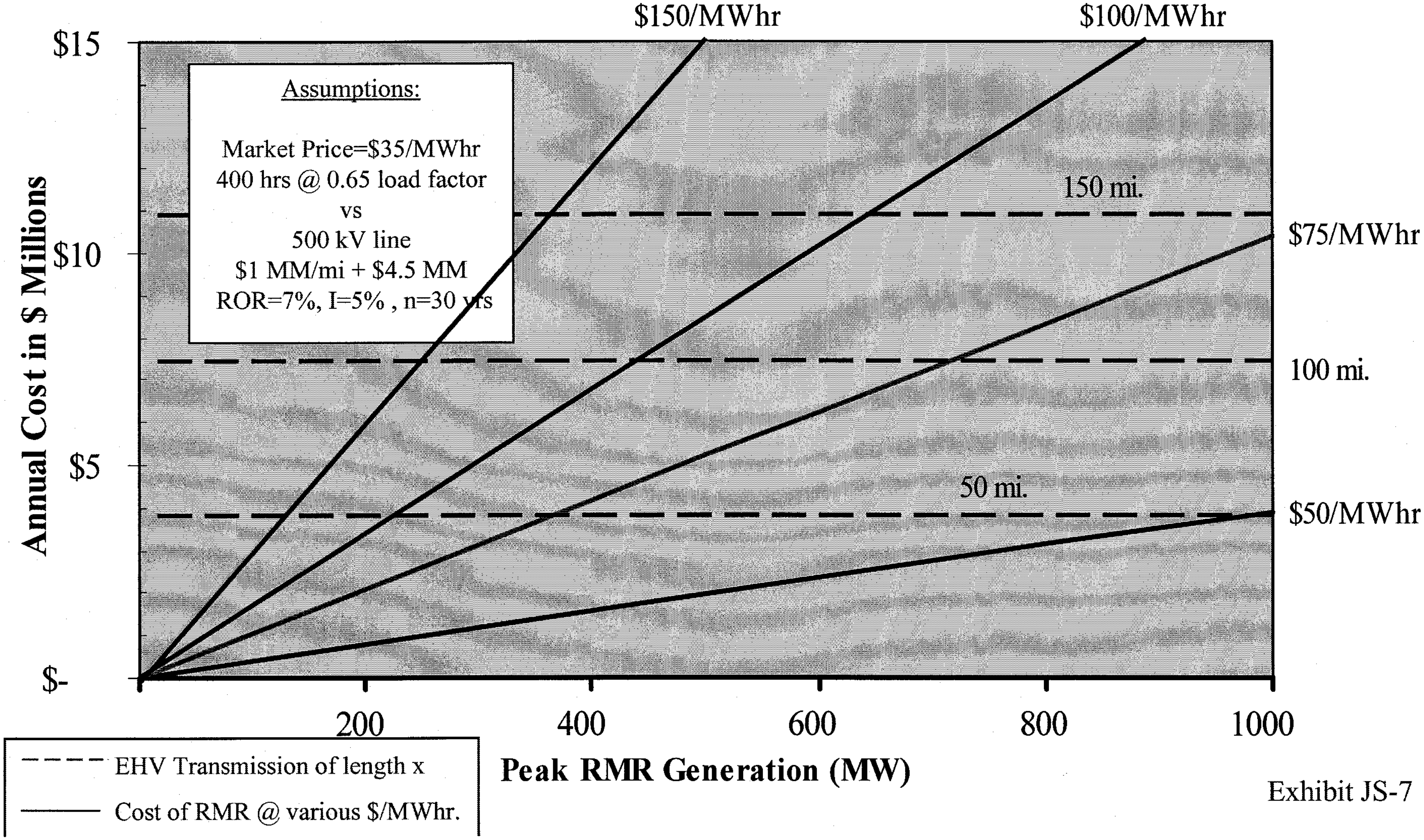


Exhibit JS-7

Formulas, Definitions, Assumptions For Exhibit JS-7

"Reliability Must-Run" is economically prudent when $C_{rmr} \leq C_a$

Where:

C_{rmr} = Cost of RMR energy during the constraint period and
C_a = Annual avoided cost of transmission line investment

$$C_{rmr} = (G_{rmr} - G_m) * L_f * P * y \quad \text{and} \quad C_a = (1 + ROR)(T_t + T_l * x) * i(1+i)^n / [(1+i)^n - 1]$$

Where:

G_{rmr} = Total operating cost of RMR unit(s) in $/MWhr.
G_m = Marginal market price of generation ($35/MWhr).
Per WGAs August 2001 Conceptual Plans for Electricity Transmission in the West report, FERCs February 2002 Economic Assessment of RTO Policy, and current WI market trends.
L_f = Seasonal load factor during constraint period (0.65 for summer).
P = Peak load in excess of transmission import capability in MW.
Begins at 427 MW in 2003 and grows to 1034 MW in 2007 for APS; begins at 354 MW in 2003 for TEP and grows to 564 MW in 2007.
y = Duration of RMR constraint in hours (400 hrs)

ROR = Annual rate of return allowed on capital investment (7%).
T_t = Transmission termination cost of new line ($4.5 million).
Assumes a breaker and a one half scheme at each end of the line.
T_l = Transmission line capital cost per mile ($1 million/mi.).
Assumes $1 million per mile for 345kV and 500 kV using steel poles.
n = Economic life of new transmission line (30 yrs).
i = Annual interest rate (5%).
x = Length of new EHV transmission line (mi.)

Exhibit JS-8

Competitive Generation Requirement*

Area = WSCC,
Control Area,
RTO,
State,
or Utility

Area Load
- Interruptible
+ Net Export

Reserve Load Responsibility
+ Reserves

Min. Gen. Req.
+ Comp. Supply Margin

Total Gen. Req.

Plng Reserves
Capacity Margin
Operating Reserves

Sufficient to
ensure competitive
market prices

* Assumes no Transmission constraint

Exhibit JS-9

Proposed Plants in Arizona

Status	Year							Total MWs
	2001	2002	2003	2004	2005	2006	2007	
Commercial Operation	1,830	-	-	-	-	-	-	1,830
Under Construction	-	3,880	3,330	-	-	-	-	7,210
Reg. Approval Received	-	-	600	2,645	1,865	620	530	6,260
Application Under Review	-	-	520	-	-	-	-	520
Application Filed	-	-	-	-	-	-	-	-
Announced	-	-	520	580	-	-	2,500	3,600
Total MWs	1,830	3,880	4,970	3,225	1,865	620	3,030	19,420

05/29/2002

Note: Montezuma 520MW plant suspended plans w/o filing CEC application
Denied Projects = Big Sandy (720 MW) and Toltec (1800 MW)

Exhibit JS-10

New Power Plants 2001

Plant	Nominal Capacity (MW)	Gas Use (MMBtu/Yr)	Water Use (Acre-Ft/Yr)
Desert Basin	520	33,100,000	4,200
Griffith	650	36,266,400	3,060
W. Phoenix	120	6,619,200	1,083
South Point	540	35,000,000	4,500
TOTAL	**1,830**	**110,985,600**	**12,843**

Exhibit JS-11

2003
Competitive Generation (MW)

Operational 2001	
Griffith Energy	650
Desert Basin	520
South Point	540
W. Phoenix	120
	1,830

2002	
Arlington Valley I	580
Gila River 1,2	1,040
Kyrene	250
Redhawk 1,2	1,060
Sundance CTs	450
W. Phoenix	500
	3,880

2003

Arlington Valley II	600	Harquahala	1,040
Gila River 3,4	1,040	Mesquite	1,250
			3,930

Exhibit JS-12

New AZ Power Plants, Gas Supply Basins And Pipelines

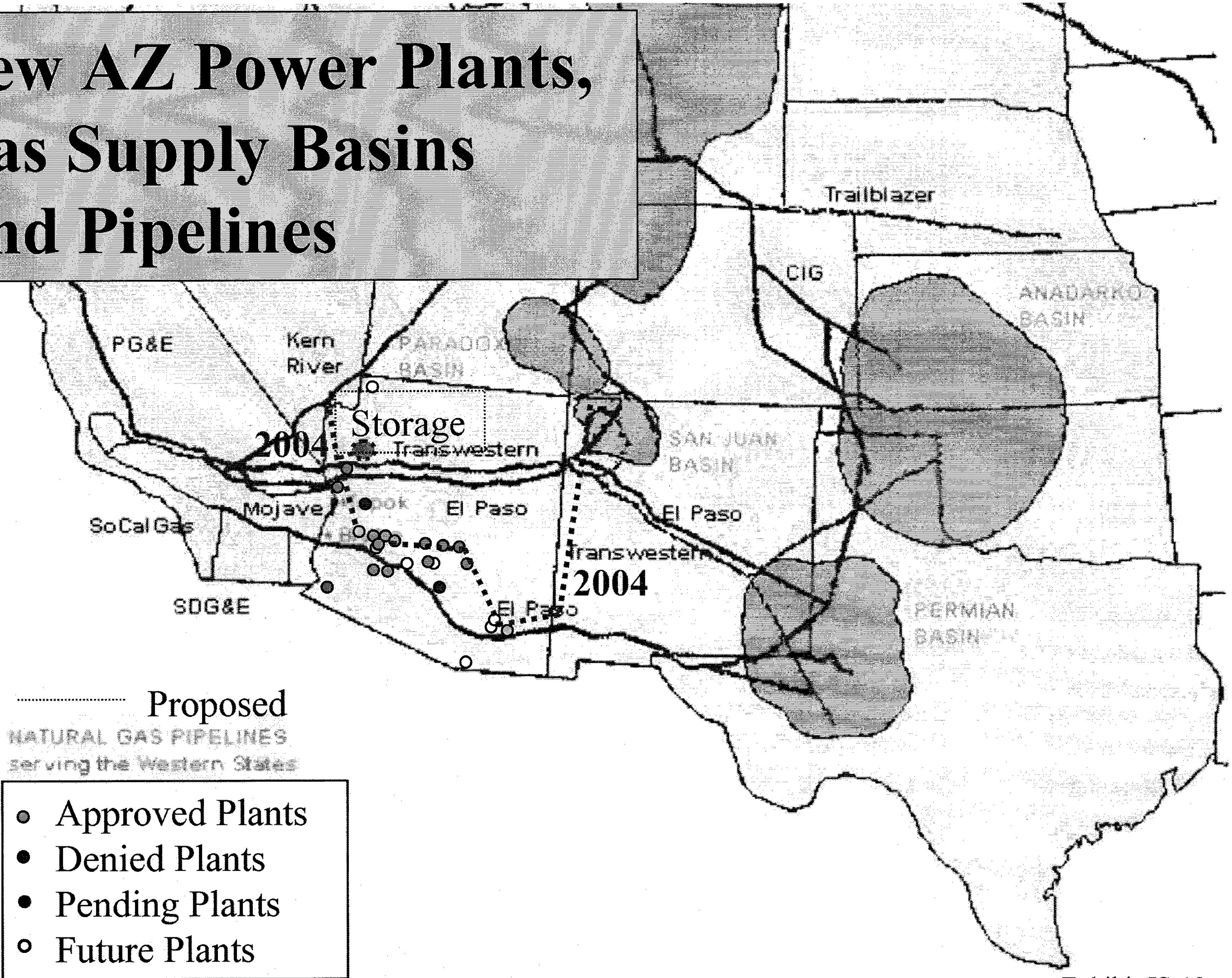


Exhibit JS-13

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	)	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	)	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDIPENDENT SCHEDULING ADMINISTRATOR.	)	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	)	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	)	DOCKET NO. E-01933A-98-0471

DIRECT

TESTIMONY

OF

ERINN ANDREASEN

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

MAY 29, 2002

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Erinn Andreasen. My business address is 1200 West Washington St., Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division of the Arizona Corporation Commission as a Public Utilities Analyst.

Q. Please describe your educational background and recent work experience.

A. In 1999, I graduated summa cum laude from Arizona State University, receiving a Bachelor of Science degree in Agribusiness with a specialization in international business. Since, I have completed 21 hours in the MBA program at the University of Phoenix and am scheduled to complete my Masters degree in 2003. I have worked at the Commission for two years as an Economist and a Public Utilities Analyst. My current duties include the review and evaluation of applications for electric Certificates of Convenience and Necessity ("CC&N"), electric utility special contracts, demand-side management programs, and utility tariff filings. I have testified in several electric CC&N proceedings.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-00000A-02-0051?

A. Yes.

Q. What is the purpose of your testimony?

A. I will explain the purpose and concept of an Electric Competition Advisory Group ("Advisory Group") and present a recommendation to create the proposed Advisory Group.

ELECTRIC COMPETITION ADVISORY GROUP

Q. Is there currently a formal means for communications and information sharing among stakeholders and Commission Staff in the electric industry regarding topics such as wholesale and retail market transactions, market structures, and impediments to competition?

A. No. Through its ordinary duties, Commission Staff ("Staff") communicates with industry participants and monitors the industry in an informal manner. However, a more formal approach toward facilitating communication and information sharing has not been established.

Q. What do you recommend as a means to facilitate the sharing of this type of information among stakeholders, market participants, and Staff in the electric industry?

A. I recommend that an Advisory Group be formed.

Q. What is the purpose of the Advisory Group?

A. The Advisory Group would observe market activities and provide a forum for Staff, stakeholders, and market participants to share information and discuss issues regarding wholesale and retail market transactions, market structures, impediments to competition, and other matters. The Advisory Group may also be asked by Staff to provide input regarding the market power study and market power mitigation plan that is described in the direct testimony of Matt Rowell.

Q. How will an Advisory Group be beneficial?

A. The Advisory Group is needed to facilitate the sharing of information so that Staff can make reports and policy recommendations to the Commission based on recent knowledge of market activities from stakeholders and market participants.

Q. When would Staff provide reports and policy recommendations to the Commission?

A. Staff would report to the Commission on the issues discussed among the Advisory Group participants and make policy recommendations on a periodic basis.

Q. Who do you anticipate participating in the Advisory Group?

A. The group would consist of Staff, stakeholders, and market participants including: independent power producers, transmission users, Electric Service Providers, utilities, consumer advocates, and various associations.

Q. Is participation in the Advisory Group mandatory?

A. No. Participation is voluntary. However, Staff strongly encourages participation.

Q. Who will chair the Advisory Group?

A. The Director of the Utilities Division or the Director's designee.

Q. Will the Advisory Group provide a formal market monitoring function requiring market studies or analyses provided by its stakeholders, market participants, or Staff?

A. No. The Advisory Group would not have an enforcement function and would not be requiring or performing in-depth market monitoring studies or analysis. Staff would rely on the information presented by the stakeholders and market participants to become aware of both retail and wholesale market concerns.

Q. The Federal Energy Regulatory Commission ("FERC") is making efforts to address market monitoring in the wholesale market. Is there a role for states to participate in creating market monitoring performance measures?

A. In its Staff Working Paper on Standard Market Design, FERC Staff has indicated that the states would have a role in developing performance measures for market monitoring of activities performed by Regional Transmission Organizations.[1]

Q. Would the Advisory Group provide comments to Staff on market monitoring issues?

A. Staff could request that the Advisory Group provide feedback on these types of issues as well as other issues that Staff or the Commission finds to be relevant.

Q. If the Commission does not have jurisdiction over the wholesale market, why is Staff concerned with wholesale transactions and market structures?

A. Staff is concerned with transactions and structures in the wholesale market as they may ultimately have an effect on events in the retail market. Staff is also interested in the wholesale market to the extent that the Commission would deem it necessary to intervene in proceedings at FERC.

---

[1] FERC Working Paper on Standardized Transmission Service and Wholesale Market Design, p. 24.

STAFF RECOMMENDATION

Q. What do you recommend in regard to the formation of the Advisory Group?

A. I recommend that the Commission form an Electric Competition Advisory Group for purposes of facilitating communication and the sharing of information among Staff, stakeholders, and market participants about wholesale and retail market transactions, market structures, and impediments to competition.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.)	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.)	DOCKET NO. E-01345A-01-0822
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IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.)	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF T[illegible]ON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.)	DOCKET NO. E-01933A-98-0471

DIRECT

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

MAY 29, 2002

Testimony-CodeOfConduct.doc

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APPENDIX

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington St., Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division of the Arizona Corporation Commission as a Public Utilities Analyst. My duties include evaluation of electric utility special contracts, review of utility tariff filings, assessment of utility demand-side management programs, and analysis of electric utility production costs and marginal costs. A copy of my résumé is provided in the Appendix.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-00000A-02-0051?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony is concerned with affiliate relationships. I will present recommendations regarding the need for a new code of conduct between affiliates.

PROBLEMS WITH AFFILIATE RELATIONSHIPS

Q. What are affiliate relationships?

A. Affiliate relationships are interactions between a public utility and any other entity directly or indirectly controlling or controlled by, or under direct or indirect common control with, the public utility. Control means the power to direct the management policies of an entity.

Q. What are some of the problems associated with affiliate relationships?

A. Some of the problems include the potential for self-dealing, preferential treatment to affiliates, and cross-subsidization.

Q. Please explain what is meant by the term *self-dealing*.

A. Self-dealing involves a utility procuring capacity, power, or other energy services from an affiliate. The use of utility-owned capacity to deliver power is also a form of self-dealing. Although self-dealing can have advantages when there are economies of scope or when an affiliate is the lowest-cost supplier, self-dealing also provides the utility opportunities and incentives to engage in inefficient or abusive behavior harmful to ratepayers. One form of abusive self-dealing is transfer pricing. Transfer pricing occurs if an affiliate is able to charge the utility above-market prices for goods and services knowing that the increased prices will be passed through to ratepayers.

Q. Please explain what is meant by *preferential treatment to affiliates*.

A. Preferential treatment occurs when the utility's affiliates or customers of its affiliates receive different treatment by the utility than the treatment the utility provides to other, unaffiliated companies or their customers.

Q. Please explain what is meant by *cross-subsidization*.

A. Cross-subsidization occurs when costs associated with providing a service are recovered through prices charged for another service. Cross-subsidization also includes the transfer of tangible or intangible assets from the utility to affiliates. Consumers pay higher rates to cover the costs of the unregulated companies. One form of cross-subsidization is a disproportionate allocation of common or joint costs to the utility (cost shifting). Another form of cross-subsidization is utility payments to an affiliate that are higher than market level. In addition, when unregulated affiliates are subsidized by regulated companies, they can undercut market prices (predatory pricing). This cross-subsidization retards market competition and deters new market entrants. While cross-subsidies may initially allow unregulated affiliates to offer lower prices, prices will eventually rise once existing competitors have been driven out and potential new entrants discouraged from entering the market.

Q. What are *Codes of Conduct*?

A. Codes of Conduct are safeguards governing the behavior and structure of utility relationships with affiliates. The purposes of Codes of Conduct include: creating barriers to self-dealing, preventing preferential treatment to affiliates, ensuring that utility ratepayers do not subsidize unregulated utility affiliates, and mitigating market power.

INADEQUACIES OF EXISTING RULES OF CONDUCT TO PREVENT PROBLEMS

Q. What rules of conduct currently exist that deal with affiliate relationships?

A. The Commission has Public Utility Holding Companies and Affiliated Interests rules (A.A.C. R14-2-801 through -806) and a Code of Conduct section (A.A.C. R14-2-1616) within the Retail Electric Competition rules. The Federal Energy Regulatory Commission (FERC) also has rules of conduct.

Q. Please describe the Commission's Public Utility Holding Companies and Affiliated Interests rules.

A. The Public Utility Holding Companies and Affiliated Interests rules apply to all Class A investor-owned utilities under the Commission's jurisdiction. Features of the rules include the following:

- A utility or affiliate has to provide notice of intent to organize or reorganize a public utility holding company.
- A utility cannot transact business with an affiliate unless the affiliate provides the Commission access to its books and records.

- A utility needs prior Commission approval before obtaining a financial interest in an affiliate, lending $100,000 or more for a period of at least 12 months to an affiliate, using utility funds to form a subsidiary, or divesting itself of a subsidiary.
- Annually, utilities and holding companies must file descriptions of diversification activities and plans.

Q. Please describe the Commission's Code of Conduct section within the Retail Electric Competition rules.

A. The Code of Conduct rule applies to any Affected Utility which plans to offer Noncompetitive Services and which plans to offer Competitive Services through its competitive electric affiliate or electric service provider (ESP). The Code of Conduct only applies to the relationship between the Affected Utility and its ESP affiliate. The Code of Conduct addresses the following subjects:

- cross subsidization between utilities and competitive affiliates
- access to confidential information by competitive affiliate
- joint employment by utility and competitive affiliate
- use of utility's name or logo by competitive affiliate
- preferential treatment toward competitive affiliate
- joint advertising, joint marketing, and joint sales by utility and competitive affiliate
- transactions between utilities and competitive affiliates
- representation to customers of better service as result of affiliation
- complaint procedures

Q. Please describe FERC's rules of conduct.

A. FERC has two kinds of rules of conduct. One is standards of conduct for transmission providers (18CFR37.4). The standards require that a transmission provider's transmission function operate independently from its marketing and sales functions and that a transmission provider must treat all transmission customers on a nondiscriminatory basis. FERC has issued a Notice of Proposed Rulemaking to have new standards of conduct that would apply uniformly to both natural gas pipelines and transmitting public utilities.

FERC also requires a code of conduct for a utility to transact business with affiliates at market-based rates. This code places restrictions on the sales of non-power goods and services between the utility and its marketing affiliates. It may also include requirements to separate marketing affiliate employees from utility employees and restrictions on the sharing of information.

Q. Do the currently existing rules of conduct effectively deal with the problems associated with affiliate relationships that you described above?

A. The Public Utility Holding Companies and Affiliated Interests rules do not address wholesale power transactions between affiliated entities. The Code of Conduct section within the Retail Electric Competition rules is designed to prevent anti-competitive activities by a utility and its competitive electric affiliate (Electric Service Provider). It does not cover activities between a utility and any other affiliate. The FERC standards of conduct for transmission providers do not address types of market power abuse, such as cross-subsidization and transfers of information. The FERC code of conduct for a utility to transact business with affiliates at market-based rates places restrictions on non-power sales but does not address power sales.

OTHER STATES' EXPERIENCES

Q. How have other states dealt with the problems of affiliate relationships?

A. One example is Kentucky. Kentucky has a statute (KRS Chapter 278) relating to utilities and affiliates of utilities. The statute prohibits regulated utilities from using utility revenues to fund unregulated affiliates, requires separate recordkeeping, specifies cost allocation procedures, provides requirements regarding affiliate transaction pricing, governs sharing of information and resources, requires all dealings between a utility and a nonregulated affiliate to be at arm's length, prohibits undue preferential treatment to affiliates, prohibits a utility from entering into financing arrangements for nonregulated activities through an affiliate that would permit a creditor upon default to have recourse to the utility's assets, and contains other requirements.

Q. Are there other examples?

A. Yes. Maryland has standards of conduct for all gas and electric utilities and their core and non-core affiliates (Order No. 76292). The standards are intended to 1) prevent cross-subsidization of affiliates, 2) prevent affiliates from gaining any improper advantage in their competitive markets because of their affiliation to the regulated utility, 3) minimize the sharing of confidential information, 4) protect the privacy of consumers, and 5) prohibit discrimination in the provision of regulated services. There is a separate code of conduct for utilities and their affiliated electric generation companies (GENCOs). The GENCO code of conduct is intended to foster competitive electric generation markets, minimize market power, and help eliminate any inherent advantages that a GENCO might possess.

Massachusetts has standards of conduct for distribution companies and their affiliates (220 CMR 12.00). Provisions in the standards include restrictions on the release of proprietary customer information by a distribution company to an affiliate and requirements regarding the pricing of transactions between distribution companies and affiliates.

Q. Why have these states established standards of conduct between affiliates?

A. These states have established standards of conduct between affiliates because they are trying to prevent conduct on behalf of the utility and its affiliates that would interfere with public policies that those states are trying to foster. Similarly, in this case, Staff recommends that the Commission require adoption of codes of conduct to further Arizona public policy.

STAFF RECOMMENDATIONS

Q. What does Staff recommend as a solution to the problems associated with affiliate relationships in Arizona?

A. Staff recommends the following:

1) Any investor-owned utility that wants to purchase power from an affiliate within 12 months of a Commission Decision in this docket must file a code of conduct for Commission approval within 90 days of a Commission Decision in this docket.

2) Any investor-owned utility that has already purchased power from an affiliate must file a code of conduct for Commission approval within 90 days of a Commission Decision in this docket.

3) Any investor-owned utility that has not made a filing in response to nos. 1 or 2 above but in the future plans to purchase power from an affiliate must obtain Commission approval of a code of conduct before executing any affiliate transactions.

4) Prior to a transfer of generation assets to an affiliate, an investor-owned utility must file a code of conduct for Commission approval unless such code of conduct has already been filed in response to recommendations nos. 1, 2, or 3 above.

Q. What entities should be covered by the proposed code of conduct?

A. The code of conduct should cover an investor-owned electric utility regulated by the Commission and all affiliates from which the utility may purchase power or which are in energy-related fields.

Q. What items should be included in the proposed code of conduct?

A. The code of conduct should address, at a minimum, arm's-length transactions; access to confidential information; cross-subsidization; preferential treatment to affiliates; joint employment and employee transfer issues; sharing of office space, equipment, and services; proprietary customer information; financing arrangements with affiliates; and conflict of interest.

Q. Do you have specific recommendations in regard to addressing arm's-length transactions in the code of conduct?

A. Yes. Arm's-length transactions are defined as transactions negotiated by unrelated parties, each acting in his or her own self-interest. Therefore, Staff recommends that the same representative should not appear on both sides of a transaction. Second, for ratemaking purposes, sales or transfers from an affiliate to the utility should be priced at the lower of cost or market. Third, for ratemaking purposes, sales or transfers from the utility to an affiliate should be priced at the higher of cost or market.

Q. Does this conclude your testimony?

A. Yes.

RESUME

BARBARA KEENE

Education

B.S.	Political Science, Arizona State University (1976)
M.P.A.	Public Administration, Arizona State University (1982)
A.A.	Economics, Glendale Community College (1993)

Additional Training

Management Development Program - State of Arizona, 1986-1987
UPLAN Training - LCG Consulting, 1989, 1990, 1991
various seminars, workshops, and conferences on energy efficiency, rate design, computer skills, labor market information, training trainers, and Census products

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst V (October 2001-present), Senior Economist (July 1990-October 2001), Economist II (December 1989-July 1990), Economist I (August 1989-December 1989). Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Department of Economic Security, Research Administration, Economic Analysis Unit: Labor Market Information Supervisor (September 1985-August 1989), Research and Statistical Analyst (September 1984-September 1985), Administrative Assistant (September 1983-September 1984). Supervised professional staff engaged in economic research and analysis. Responsible for occupational employment forecasts, wage surveys, economic development studies, and over 50 publications. Edited the monthly **Arizona Labor Market Information Newsletter**, which was distributed to about 4,000 companies and individuals.

Testimony

Resource Planning for Electric Utilities (Docket No. U-0000-90-088), Arizona Corporation Commission, 1990; testimony on production costs and system reliability.

Trico Electric Cooperative Rate Case (Docket No. U-1461-91-254), Arizona Corporation Commission, 1992; testimony on demand-side management and time-of-use and interruptible power rates.

Navopache Electric Cooperative Rate Case (Docket No. U-1787-91-280), Arizona Corporation Commission, 1992; testimony on demand-side management and economic development rates.

Arizona Electric Power Cooperative Rate Case (Docket No. U-1773-92-214), Arizona Corporation Commission, 1993; testimony on demand-side management, interruptible power, and rate design.

Tucson Electric Power Company Rate Case (Docket Nos. U-1933-93-006 and U-1933-93-066) Arizona Corporation Commission, 1993; testimony on demand-side management and a cogeneration agreement.

Resource Planning for Electric Utilities (Docket No. U-0000-93-052), Arizona Corporation Commission, 1993; testimony on production costs, system reliability, and demand-side management.

Duncan Valley Electric Cooperative Rate Case (Docket No. E-01703A-98-0431), Arizona Corporation Commission, 1999; testimony on demand-side management and renewable energy.

Tucson Electric Power Company vs. Cyprus Sierrita Corporation, Inc. (Docket No. E-0000I-99-0243), Arizona Corporation Commission, 1999; testimony on analysis of special contracts.

Arizona Public Service Company's Request for Variance (Docket No. E-01345A-01-0822), Arizona Corporation Commission, 2002; testimony on competitive bidding.

Publications

Author of the following articles published in the *Arizona Labor Market Information Newsletter*:

"1982 Mining Employees - Where are They Now?" - September 1984
"The Cost of Hiring" and "Arizona's Growing Industries" - January 1985
"Union Membership - Declining or Shifting?" - December 1985
"Growing Industries in Arizona" - April 1986
"Women's Work?" - July 1986
"1987 SIC Revision" - December 1986
"Growing and Declining Industries" - June 1987
"1986 DOT Supplement" and "Consumer Expenditure Survey" - July 1987
"The Consumer Price Index: Changing With the Times" - August 1987
"Average Annual Pay" - November 1987

"Annual Pay in Metropolitan Areas" - January 1988
"The Growing Temporary Help Industry" - February 1988
"Update on the Consumer Expenditure Survey" - April 1988
"Employee Leasing" - August 1988
"Metropolitan Counties Benefit from State's Growing Industries" - November 1988
"Arizona Network Gives Small Firms Helping Hand" - June 1989

Major contributor to the following books published by the Arizona Department of Economic Security:

Annual Planning Information - editions from 1984 to 1989
Hispanics in Transition - 1987

(with David Berry) "Contracting for Power," *Business Economics*, October 1995.

(with Robert Gray) "Customer Selection Issues," *NRRI Quarterly Bulletin*, Spring 1998.

Reports

(with Task Force) *Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees*. Arizona Corporation Commission, 1992.

Customer Repayment of Utility DSM Costs, Arizona Corporation Commission, 1995.

(with Working Group) *Report of the Participants in Workshops on Customer Selection Issues*," Arizona Corporation Commission, 1997.

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.)	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.)	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.)	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES AND COMPLIANCE DATES.)	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.)	DOCKET NO. E-01933A-98-0471

DIRECT

TESTIMONY

OF

DAVID A. SCHLISSEL

SYNAPSE ENERGY ECONOMICS, INC.

APPEARING ON BEHALF OF UTILITIES DIVISION

MAY 29, 2002

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I. QUALIFICATIONS

Q. Please state your name, position and business address.

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Staff of the Arizona Corporation Commission. ("Staff")

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in economic and policy analysis of the electric industry, particularly issues of restructuring, market power, consumer protection, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, need for new transmission and generation capacity, and nuclear power.

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 24 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My clients have included the Staff of the California Public Utilities Commission, the Staff of the Arizona Corporation Commission, the Arkansas Public Service Commission Staff, the Vermont Department of Public Service, municipal utility systems in Massachusetts, New York, Texas, and North Carolina, and the Attorney General of the Commonwealth of Massachusetts.

I have testified before state regulatory commissions in Arizona, New Jersey, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, and Wisconsin and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit DAS-1.

II. CONCLUSION AND RECOMMENDATION

Q. What is the purpose of your testimony.

A. I have been asked by the ACC Staff to examine whether the transfer and separation of generating assets by the Arizona Public Service Company ("APS") and/or the Tucson Electric Power Company ("TEP") will create market power issues. This testimony presents the results of my investigation of this issue.

Q. Please summarize your conclusion concerning the transfer and separation of APS' generating assets.

A. As a result of the transfer and separation of its generating assets, APS and its affiliates would be able to exercise market power, most significantly in the transmission constrained areas in the Phoenix Valley and Yuma.

Q. Please summarize your conclusion concerning the transfer and separation of TEP's generating assets.

A. As a result of the transfer and separation of its generating assets, TEP and its affiliates would be able to exercise market power in the Tucson load constrained area which contains all of the Company's retail loads.

Q. What is your recommendation?

A. APS and TEP should be required to present detailed analyses of the potential for the exercise of market power before the Commission grants approval for the transfer and separation of their generating assets to affiliates.

III. ARIZONA PUBLIC SERVICE COMPANY

Q. Has APS indicated that it believes that there would be a competitive wholesale market if its generating assets are transferred to its affiliate Pinnacle West Energy Corporation ("PWEC") in the near future?

A. No. In fact, in its testimony in Docket No. E-01345A-01-0822, APS repeatedly emphasized that there will not be sufficient competitive generating facilities to supply even 50 percent of its standard offer loads in 2003 or in any year in the near future. [1] The Company also has said that existing transmission constraints will prevent those new merchant plants currently under construction from supplying significant quantities of power to its standard offer customers.

> Another fact is that it is not presently possible to obtain 50%, let alone 100%, of APS' requirements from the Palo Verde hub to the Company's' primary and secondary load centers, and yet it is precisely in the Palo Verde area that most of the Merchant Intervenors have elected to build their plants or to interconnect with the Arizona grid. Others, although located far from Palo Verde, are also positioned far from the APS transmission system, with no practical way to reach APS.[2]

In fact, APS has argued that while it may be "theoretically possible" that 700 MW of load in its non-transmission constrained areas could be competitively bid, it has serious reservations about the feasibility of such an approach. [3]

Even if it were possible to competitively bid this 700 MW of load in non-transmission constrained areas, the Company's remaining standard offer loads, including the customers in the Phoenix Valley and Yuma load pockets, would be at risk for higher rates should APS effectively exercise its market power to raise wholesale power costs.

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1 Direct Testimony of William H. Hieronymus on Behalf of Arizona Public Service Company in Docket No. E-01345A-01-0822, at page 24, lines 11-13.

2 Direct Testimony of Jack E. Davis on Behalf of Arizona Public Service Company, Docket No. E-01345A-01-0822, at page 6, lines 5 to 11.

3 Rebuttal Testimony of Cary Deise on Behalf of Arizona Public Service Company, Docket No. E-01345A-01-0822, at page 18, line 4, to page 19, line 14.

Q. Has APS implied that it might seek to profit from the limited competition for serving its standard offer loads?

A. Yes. APS witness Hieronymus in Docket No. E-01345A-01-0822 has testified that:

> Moreover, the aggregate capacity available from these [merchant generating facilities], even assuming they could deliver to APS loads, is less than half of the PWEC load that would be put out to bid. Of course, PWEC or PWCC could bid, but would do so with the knowledge that it faced limited competition and that some of its capacity likely would be needed.[4]

This suggests that APS might seek to take advantage of its market power.

Q. Please explain how you have evaluated whether the transfer and separation of APS' generating assets will create market power concerns?

A. As I will explain later in this testimony, a detailed system simulation analysis needs to be performed to determine the extent to which APS will be able to exercise market power in its service territory when its generating assets are transferred to PWEC. This system simulation analysis would reflect existing transmission constraints and planned transmission and generation upgrades.

However, I have not had the opportunity to perform such an analysis due to the limited time provided for the preparation of this testimony. Therefore, I have performed a screening analysis using the new Supply Margin Assessment ("SMA") test that FERC has said should be used pending completion of a generic rulemaking proceeding.[5]

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4 Ibid., at page 3, line 20, to page 4, line 2.

5 FERC Order in Dockets Nos. ER96-2495-015, ER97-4143-003, ER97-1238-010, ER98-2075-009, ER98-542-005, ER91-569-009 and ER97-4166-008, issued November 20, 2001, at page 7.

Q. Has FERC explained why it believes that this SMA screen is an appropriate test for examining whether an applicant can exercise generation market power?

A. Yes. FERC explained that because of structural changes and corporate realignments that have occurred and continue to occur in the electric industry, earlier analyses no longer adequately protect customers against generation market power in all circumstances.[6]

According to FERC, as a method for assessing whether an applicant has generation market power, the SMA screen builds on and improves the earlier methodology in two ways:

> First, in determining the geographic market, the SMA considers transmission constraints. Thus, the SMA can more accurately determine what supply can reach buyers to compete with the applicant.
>
> Second, in determining the size that triggers generation market power concerns, the SMA establishes a threshold based on whether an applicant is pivotal in the market, i.e., whether at least some of the applicant's capacity must be used to meet the market's peak demand. When an applicant is pivotal, it is in a position to demand a high price above competitive levels and be assured of selling at least some of its capacity. An applicant will be pivotal if its capacity exceeds the market's surplus of capacity above peak demand -- that is, the market's supply margin. Thus, an applicant will fail the SMA screen if the amount of its capacity exceeds the market's supply margin. By contrast, under the hub-and-spoke method, an applicant would pass the screen if its market share were less than 20 percent, even if its capacity were pivotal. The SMA's supply margin threshold is a better screen for market power because, unlike the 20 percent market share screen, it is sensitive to the relative scarcity of electricity supply available from suppliers other than the applicant in the applicable market. Effectively, the supply margin threshold identifies whether the applicant is a must-run supplier needed to meet peak load in the control area. Thus, the supply margin is sensitive to the potential for the applicant to successfully withhold supplies in the market in order to raise prices.[7]

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6 Ibid.

7 Ibid., at pages 7 to 8.

In other words, FERC has found that an applicant is "pivotal" and has the ability to exercise market power within its control area market because its generation is needed to meet the market's peak demand.

Q. Has APS acknowledged that its generation is needed to meet the peak demand of its customers in the Phoenix Valley transmission constrained area (i.e., load pocket)?

A. Yes. APS rebuttal witness Deise in Docket No. E-01345A-01-0822 presented an APS Valley Import Analysis that showed that the Company would need 427 MW of its in-Valley capacity to meet projected peak loads in 2003.[8] The amount of in-Valley capacity needed to meet projected peak demands in subsequent years would increase to 1,034 MW by 2007 but would decrease in 2008 following the completion of planned transmission system upgrades.

Year	APS Valley Load	APS Transmission Import Capability	APS In-Valley Generation Requirement
2003	4112	3685	427
2004	4256	3685	571
2005	4405	3685	720
2006	4559	3685	874
2007	4719	3685	1034
2008	4884	4685	199
2009	5055	4685	370
2010	5232	4685	547

Obviously, APS dependence on in-Valley generation units to meet projected peak demands will continue to increase after 2007 if the proposed transmission system upgrades are not completed as currently planned.

Consequently, under FERC's SMA screen test, APS would have the ability to exercise market power within its Phoenix Valley service area because its generation would be needed to meet the area's peak demand.

8 Rebuttal Testimony of Cary Deise on Behalf of Arizona Public Service Company in Docket No. E-01345A-01-0822, Schedule CD-3R.

Q. Does APS need to operate its in-Valley generating facilities for a significant number of hours each year to serve customer demands?

A. Yes. For example, APS has indicated that it had to operate some amount of "must-run" in-Valley generation for 956 hours in the year 2000.[9]

Q. Would APS similarly have the ability to exercise market power in its Yuma load pocket?

A. Yes. The ACC Staff has found that APS' transmission import capability into the existing Yuma load pocket will be inadequate to meet projected peak demands at least until 2004 when a new transmission line is scheduled for completion.[10] Until that time, at least, APS will rely on generation inside its Yuma load pocket to meet some of its projected peak demands.

Q. Is it only the need to rely on generating facilities inside these load pockets that creates the potential for market power?

A. No. The potential for APS to exercise market power also is enhanced by the fact that, for the foreseeable future at least, some APS or affiliate-owned generating facilities located outside the Phoenix Valley will continue to be needed to serve both peak and non-peak customer demands within that load pocket. This is due to the limited amount of merchant capacity that will be capable of being imported into the Phoenix Valley.[11] APS' control over the existing transmission system also creates vertical market power concerns about its possible use of that control to advantage its own affiliates while disadvantaging competitors.

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9 Revised Biennial Transmission Assessment, 2000-2009, Revised July 2001, Appendix D, at page 16.

10 Revised Biennial Transmission Assessment, 2000-2009, Revised July 2001, Appendix D, at pages 32 and 33.

11 See the Direct Testimony of Jack E. Davis on Behalf of Arizona Public Service Company, Docket No. E-01345A-01-0822, at page 6, lines 5 to 11 and the Rebuttal Testimony of Cary Deise on Behalf of Arizona Public Service Company, Docket No. E-01345A-01-0822, at page 18, line 4, to page 19, line 14.

Q. Has APS acknowledged that the existence of the Phoenix Valley and Yuma load pockets creates market power concerns?

A. Yes. APS witness Hieronymus testified in Docket Nos. E-01345A-98-0473, E-01345A-97-0773, and RE-00000C-94-0165 that the existence of the Phoenix Valley, Yuma and Douglas load pockets creates market power concerns:

> A load pocket is a geographic area in which the peak load exceeds the capability of the transmission system to allow power imported from outside the pocket to fully and reliably serve load. Usually, this limit is the thermal limit of the transmission lines entering the pocket. Since imports cannot fully meet load, it is necessary that some part of the load must be met by running generation located within the pocket. Other concerns, such as system stability and voltage problems, may also dictate that generation within the pocket must be run.
>
> * * * *
>
> [load pockets create market power concerns] because only generation within the load pocket can meet the load that exceeds the import limit. If there is only one, or very few owners of generation in the pocket, and the prices that they charge are not regulated, the owner(s) may be able to charge excessive prices. This will be true even if the market in the area surrounding the pocket is competitive.[12]

This is precisely what the situation in the Phoenix Valley will be if APS is allowed to transfer its generating assets to its PWEC affiliate.

Q. Did APS admit that its unregulated affiliate, then called Genco, but now named PWEC, could exercise market power in the pricing of the output of its in-pocket generating units?

A. Yes. Mr. Hieronymus acknowledged that APS theoretically could charge above competitive prices when its units within the Phoenix Valley, Yuma, and Douglas load pockets must run:

> In the case of the Yucca and Douglas CTs it would be able to charge above competitive prices during those hours when the units are must

12 Rebuttal Testimony of William H. Hieronymus on Behalf of Arizona Public Service Company, Docket Nos. E-01345A-98-0473, E-01345A-97-0773, RE-00000C-94-0165, at page 5, lines 5 to 17.

> run in the absence of regulation. In the case of the valley units, APS competes with SRP, and SRP has sufficient generation in the valley that APS generation is not required. However, with only two sellers to meet the roughly 1,000 MW of peak load that cannot be met with imports, there may be a concern that the prices charged for in-valley generation will not be competitive.[13]

Q. Did Mr. Hieronymus believe that APS actually would be able to exercise market power in the pricing of the generation within the existing load pockets?

A. No. He testified that FERC would act to protect consumers where the existence of load pockets creates the ability to exercise market power.[14]

Q. Do you agree that the Commission can rely on FERC to protect Arizona consumers against the possibility that APS will exercise market in the Phoenix Valley, Yuma, and Douglas load pockets?

A. No. Given FERC's failure to act in an effective and timely manner to protect purchasers of wholesale energy in California from widespread market power abuses, I don't believe that the ACC should rely on FERC to protect Arizona consumers.

Q. Has APS estimated how much of its load could be competitively bid in the near future given the current transmission system and planned generation and transmission additions?

A. Yes. As I noted earlier, APS rebuttal witness Deise testified in Docket No. E-01345A-01-0822 that it might be "theoretically possible" to competitively bid up to 700 MW of APS' unconstrained loads in its Northern Arizona, Southern Arizona and Eastern Mining areas; but he had serious reservations about the feasibility of such an approach.[15]

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13 Ibid., at page 7, lines 1 to 8.

14 Ibid., at page 8, lines 12 to 18.

15 At page 18, line 19, to page 19, line 14.

However, Mr. Deise emphasized that it was not possible "without making a number of critical explicit or implicit assumptions" to tell the Commission how much power can be competitively bid in the Company's service area given existing transmission constraints and the design of APS' transmission system:

> For example how are the Dedicated Units being used, how specifically will the bid be structured, where will the required delivery points be located, and for what capacities at each delivery point? The bid amount also cannot be determined without knowing the exact location and operational characteristics of all the generation resources that would operate on APS' system following the competitive bid.[16]

Mr. Deise further explained that without such a detailed analysis it was not possible to determine how much of the new merchant capacity being built outside of the Phoenix Valley could be competitively bid into APS' service territory:

> I certainly agree that significant amount of new generating capacity is being constructed in Arizona and is currently planned for future construction in Arizona. I would also agree that this new capacity should allow Arizona to contribute to the supply needs of the Western Interconnection.
>
> However, much of this new capacity is relatively concentrated around the Palo Verde hub - something that is certainly not surprising given the amount of trading there and the fact the direct interconnection by generators to the "common bus" at Palo Verde reduces transmission costs to the generators. Because APS' system cannot physically take delivery of all its power requirements from one location like Palo Verde, I do not believe that the analysis of whether there is an adequate "competitive supply margin" for delivery to APS' transmission system can be performed by simply adding up all the new and planned capacity in the state and comparing it with load requirements. For APS, power would have to be delivered at all the injection points that I discussed in Part IV of my testimony, which requires a more involved analysis than the additive process that [ACC Staff witness Jerry] Smith appears to have performed in his testimony on this issue. Thus, while I agree that there is a significant amount of new generating capacity being added in Arizona and to the Western Interconnection generally, I don't believe that new capacity can simply

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16 Rebuttal Testimony of Cary Deise on Behalf of Arizona Public Service Company in Docket No. E-01345A-01-0822, at page 23, lines 4 to 12.

> be summed to determine whether there is an adequate "competitive supply margin" for APS's system ....[17]

Q. Should the Commission only be concerned about APS' ability to exercise market power during peak demand hours or should it be concerned about non-peak hours as well?

A. The Commission should be concerned about market power both in peak demand hours and in non-peak hours. Events in California have shown that generation owners have been able to raise prices by exercising market power even in off-peak hours. For example, a report by the California Independent System Operator's Department of Market Analysis issued in May of 2001 has concluded that 30 percent of wholesale energy costs during calendar year 2000 could be attributed to the exercise of market power (i.e., that wholesale energy costs were about 30 percent higher than they would have been in the absence of market power).[18] The California Independent System Operator ("CAL ISO") also found that wholesale energy prices exceeded the competitive benchmark **in all hours, under a variety of system conditions**:

> The results illustrate that market power abuse is not limited to hours when a deficiency in operating reserves requires the ISO to declare a System Emergency, much less hours in which a Stage 3 emergency has been declared. The data demonstrate that over the most recent 12-month period (including the first two months of 2001) the gap between actual wholesale prices and the proper competitive level (which takes into account spikes in natural gas prices) *continues to grow*. (emphasis in original)[19]

In fact, the CAL ISO has concluded that less than 2% of the hourly bidding profiles by the five large in-state generation owners during the period May through November 2000 displayed no clear pattern of withholding or market

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17 Ibid., at page 24, line 7, to page 25, line 3.

18 *Comments of the California Independent System Operator Corporation on FERC Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market,* dated March 22, 2001, at page 8. These comments are available at the California ISO's website at www1.caiso.com/pubinfo/FERC/filings/.

19 Ibid.

power.[20] The other 98% of the hourly bidding profiles displayed various patterns leading to inflated market prices. CAL ISO subsequently stated that it was unable to identify any hours during the period May 2000 through November 2000 in which one of the generation owners, Williams Energy Marketing & Trading Company, "did not engage in physical or economic withholding."[21]

According to CAL ISO, during the ten month period, May 2000 to February 2001, the degree of market power observed in California wholesale markets had represented additional total costs of $6.8 billion.[22] Only about $600 million of these additional costs were incurred during hours of potential resource scarcity, so that, "even excluding these hours, wholesale energy costs had been driven up over $6.2 billion since May 2000, by the exercise of market power."[23]

Q. What analyses should the Commission require APS to perform before it allows the transfer of generating assets to affiliated companies?

A. A proper analysis of the market power implications of the proposed transfer of generating assets would require an electric system simulation model to look at the hourly behavior of the market under a wide variety of physical conditions, contractual situations and bidding behaviors. Such a realistic analysis should reflect the transmission system constraints discussed in Docket No. E-01345A-01-0822 by Staff witness Smith and ACC witnesses. It also would examine the potential for the exercise of market power during both peak and non-peak hours in both peak and non-peak seasons.

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20 *Empirical Evidence of Strategic Bidding in California ISO Real-time Market*, Anjali Sheffrin, Director, Department of Market Analysis, CAL ISO, March 21, 2001, at page 8. This report available at the California ISO's website at www1.caiso.com/pubinfo/FERC/filings/.

21 *Motion to Intervene and Protest of the California Independent System Operator Corporation*, April 2, 2001, in FERC Docket No. ER99-1722-004, at page 10. A copy of this Motion is available at the California ISO's website at www1.caiso.com/pubinfo/FERC/filings/.

22 *Comments of the California Independent System Operator Corporation on FERC Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market,* dated March 22, 2001, Attachment B, at page 10. These comments are available at the California ISO's website at www1.caiso.com/pubinfo/FERC/filings/.

23 Ibid.

IV. TUCSON ELECTRIC POWER COMPANY

Q. Would a transfer and separation of Tucson Electric Power Company's ("TEP") generating assets create a similar potential for the exercise of market power?

A. Yes. All of TEP's retail load is located within its Tucson transmission limited service territory.[24] TEP projects that this load will grow from 1,889 MW in 2003 to 2,214 MW in 2010. There will be a limit on the transmission system's import capability of 1,535 MW after the second Saguaro to Tortolito 500 kV tie and transformer are installed. Thus, TEP will need to operate large amounts of generating capacity inside the load pocket in order to meet projected peak demands.[25]

Year	Load Area Peak Demand	Local Area Transmission Import Limit	TEP Local Area Generation Requirement
2003	1889	1535	354
2004	2001	1535	466
2005	2025	1535	490
2006	2082	1535	547
2007	2099	1535	564
2008	2137	1535	602
2009	2175	1535	640
2010	2214	1535	679

Applying the FERC SMA screen shows that TEP would have the ability to exercise market power within the Tucson load pocket because its generation would be needed to meet the market's peak demand.

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24 TEP April 25, 2002 response to Staff Data Request No. RTW 1-4 in Docket No. E-01933A-02-0069.

25 The information presented in this table was taken from the loads and resources table provided in TEP's April 25, 2002 response to Staff Data Request No. RTW 1-1 in Docket No. E-01933A-02-0069.

Q. What analyses should the Commission require TEP to perform before it allows the transfer of generating assets to an affiliated company?

A. As I discussed previously with regard to APS, the Commission should require that TEP present a detailed analysis of the market power implications of the proposed transfer and separation of generating assets. This analysis should use an electric system simulation model to look at the hourly behavior of the market under a wide variety of physical conditions, contractual situations and bidding behaviors.

Q. Does this complete your testimony?

A. Yes.

EXHIBIT DAS-1

David A Schlissel

Senior Consultant
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(617) 661-3248 • fax: 661-0599

SUMMARY

I have worked for twenty-seven years as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University and a law degree from Stanford Law School

PROFESSIONAL EXPERIENCE

Electric Industry Restructuring and Deregulation - Investigated whether generators have been intentionally withholding capacity in order to manipulate prices in the new spot wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales and auctions of power purchase agreements. Analyzed stranded utility costs in Massachusetts and Connecticut. Examined the reasonableness of utility standard offer rates and transition charges.

System Operations and Reliability Analysis - Investigated the causes of distribution system outages and inadequate service reliability. Evaluated the impact of a proposed merger on the reliability of the electric service provided to the ratepayers of the merging companies. Assessed whether new transmission and generation additions were needed to ensure adequate levels of system reliability. Scrutinized utility system reliability expenditures. Reviewed natural gas and telephone utility repair and replacement programs and policies.

Power Plant Operations and Economics - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Reviewed power plant operating, maintenance, and capital costs. Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors. Evaluated the reasonableness of contract provisions and terms in proposed power supply agreements.

Nuclear Power - Examined the impact of industry restructuring and nuclear power plant life extensions on decommissioning costs and collections policies. Evaluated utility decommissioning cost estimates. Assessed the potential impact of electric industry deregulation on nuclear power plant safety. Reviewed nuclear waste storage and disposal costs. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

Economic Analysis - Analyzed the costs and benefits of energy supply options. Examined the economic and system reliability consequences of the early retirement of major electric generating facilities. Quantified replacement power costs and the increased capital and operating costs due to identified instances of mismanagement.

Expert Testimony - Presented the results of management, technical and economic analyses as testimony in more than seventy proceedings before regulatory boards and commissions in twenty one states, before two federal regulatory agencies, and in state and federal court proceedings.

Litigation and Regulatory Support - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

TESTIMONY

Arizona Corporation Commission (Docket No. E-01345A-01-0822) – March 2002
The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002
Repowering NYPA's existing Poletti Station in Queens, New York.

Connecticut Siting Council (Docket No. 217) – March 2002
Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

Vermont Public Service Board (Case No. 6545) – January 2002
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

Connecticut Siting Council (Docket No. 208) – October 2001
Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001
The market power implications of the proposed merger between Conectiv and Pepco.

Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001
Commonwealth Edison Company's management of its distribution and transmission systems.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001
The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

Illinois Commerce Commission (Docket 00-0361) - August 2000
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

Vermont Public Service Board (Docket 6300) - April 2000
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999
Generation, Transmission, and Distribution system reliability.

Illinois Commerce Commission (Docket 99-0115) - September 1999
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999
Standard offer rates for Connecticut Light & Power Company.

Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999
Standard offer rates for United Illuminating Company.

Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999
Connecticut Light & Power Company stranded costs.

Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999
United Illuminating Company stranded costs.

Maryland Public Service Commission (Docket 8795) - December 1998
Future operating performance of Delmarva Power Company's nuclear units.

Maryland Public Service Commission (Dockets 8794/8804) - December 1998
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

Arkansas Public Service Commission (Docket 98-065-U) - October 1998
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

Illinois Commerce Commission (Docket 97-0015) - May 1998
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

Illinois Commerce Commission (Docket 97-0018) - March 1998
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

New Jersey Board of Public Utilities (Docket ER96030257) - August 1996
Replacement power costs during plant outages.

Illinois Commerce Commission (Docket 95-0119) - February 1996
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Utility Commission of Texas (Docket 13170) - December 1994
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

Public Utility Commission of Texas (Docket 12820) - October 1994
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

Public Utility Commission of Texas (Docket 12700) - June 1994
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

Public Utility Commission of Texas (Docket 11735) - April and July 1993
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992
United Illuminating Company off-system capacity sales.

Public Utility Commission of Texas (Docket 10894) - August 1992
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992
Whether the July 1991 outage of Millstone Unit 3 due tot he fouling of important plant systems by blue mussels was the result of mismanagement.

California Public Utilities Commission (Docket 90-12-018) - November 1991, March 1992, June and July 1993
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

Public Utility Commission of Texas (Docket 9945) - July 1991
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

Public Utility Commission of Texas (Docket 9300) - June and July 1990
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989
Boston Edison's corporate management of the Pilgrim Nuclear Station.

Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989
United Illuminating Company's off-system capacity sales.

Kansas State Corporation Commission (Case 164,211-U) - April 1989
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

Public Utility Commission of Texas (Docket 8425) - March 1989
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

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The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

Illinois Commerce Commission (Docket 87-0695) - April 1988
Illinois Power Company's planning for the Clinton Nuclear Station.

North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

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Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

North Carolina Utilities Commission (Docket E-2, Sub 526) - June 1987
Fuel factor calculations.

New York State Public Service Commission (Case 29484) - May 1987
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987
The reasonableness of certain terms in a proposed Power Supply Agreement.

Illinois Commerce Commission (Docket 86-0405) - March 1987
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

Indiana Public Service Commission (Case 38045) - December 1986
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

New York State Public Service Commission (Case 28124) - April 1986 and May 1987
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

Arizona Corporation Commission (Docket U-1345-85) - February 1986
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

New York State Public Service Commission (Case 29124) - January 1986
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

New York State Public Service Commission (Case 28252) - October 1985
A performance standard for the Shoreham nuclear power plant.

New York State Public Service Commission (Case 29069) - August 1985
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

Massachusetts Department of Public Utilities (Case 84-152) - January 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

Maine Public Utilities Commission (Docket 84-113) - September 1984
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

South Carolina Public Service Commission (Case 84-122-E) - August 1984
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

Vermont Public Service Board (Case 4865) - May 1984
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

New York State Public Service Commission (Case 28347) -January 1984
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

New York State Public Service Commission (Case 28166) - February 1983 and February 1984
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

REPORTS, ARTICLES, AND PRESENTATIONS

The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

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Cost, Grid Reliability Concerns on the Rise Amid Restructuring, with Charlie Harak, Boston Business Journal, August 18-24, 2000.

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Preliminary Expert Report in Case 96-016613, Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company, October 28, 1999.

Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation, February 1997.

Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant, August 1996.

Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs, May, 1996.

Nuclear Power in the Competitive Environment, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

Nuclear Power in the Competitive Environment, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations, a report for the Environmental Law and Policy Center of the Midwest, 1995.

Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs, July 15, 1992.

Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2, December 1991.

Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas, April 1991.

Nuclear Power Plant Construction Costs, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

Comments on the Final Report of the National Electric Reliability Study, a report for the New York State Consumer Protection Board, February 27, 1981.

OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

WORK HISTORY

2000 - Present: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: President, Schlissel Technical Consulting, Inc.

1983 - 1994: Director, Schlissel Engineering Associates

1979 - 1983: Private Legal and Consulting Practice

1975 - 1979: Attorney, New York State Consumer Protection Board

1973 - 1975: Staff Attorney, Georgia Power Project

EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981
- American Nuclear Society
- National Association of Corrosion Engineers
- National Academy of Forensic Engineers (Correspondent Affiliate)

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.)	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.)	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.)	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES AND COMPLIANCE DATES.)	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.)	DOCKET NO. E-01933A-98-0471

DIRECT

TESTIMONY

OF

NEIL H. TALBOT

SYNAPSE ENERGY ECONOMICS, INC.

APPEARING ON BEHALF OF UTILITIES DIVISION

MAY 29, 2002

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DIRECT TESTIMONY OF NEIL H. TALBOT

I. Introduction and Purpose of Testimony

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Neil H. Talbot and my business address is 22 Pearl Street, Cambridge, Massachusetts 02139.

Q. WHAT IS YOUR EMPLOYMENT?

A. I am an economic and financial consultant with Synapse Energy Economics, Inc.

Q. WHAT IS YOUR AREA OF EXPERTISE?

A. My area of expertise is electric utility economics.

Q. WHAT ARE YOUR ACADEMIC QUALIFICATIONS?

A. I obtained degrees in economics and finance from Cambridge University, England, and Boston College respectively.

Q. PLEASE OUTLINE YOUR EMPLOYMENT HISTORY.

A. Since 1968, I have been employed as an economic consultant, and during most of this period I have focused on the U.S. electric utility industry and, to a lesser extent, other public utility and energy industries. I have been associated with several consulting firms during this period -- first the Economist Intelligence Unit, London, then Arthur D. Little, Inc. of Cambridge, Mass., and later Tellus Institute of Boston and LaCapra Associates of Boston. Currently, I am employed as a consultant to Synapse Energy Economics, Inc., of Cambridge, Mass.

Q: PLEASE DESCRIBE YOUR CONSULTING WORK.

A. Since 1973, when I was retained by Potomac Electric Power Company of Washington, D.C. to do a long-term load forecast, I have spent most of my time working on the U.S. electricity industry. Since the early 1990s, most of my work has focused on industry restructuring. My professional biography is attached as Exhibit NHT-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THESE PROCEEDINGS?

A. I am a member of the Synapse Energy Economics team that has been retained by the Utilities Division ("Staff") of the Arizona Corporation Commission to investigate electricity restructuring issues in Arizona.

Q. WHAT IS THE PURPOSE OF YOUR CURRENT TESTIMONY?

A. This testimony, together with that of other members of the Staff team, addresses the "Threshold Issues" which were identified in Staff's April 23, 2002 response to the Arizona Public Service Company (APS) Motion for Determination of Threshold Issues, and certain related issues identified by Chairman Mundell. These issues include "the transfer of assets and associated market power issues, as well as the issues of the Code of Conduct, the Affiliated Interest Rules, and the jurisdictional issues raised by Chairman Mundell..."

Q. WHICH OF THESE ISSUES WILL YOU ADDRESS?

A. First, I will address the presence of market power in Arizona electricity markets, and the implications thereof. On this subject, I will rely in part on data on Arizona electricity markets provided by Staff witness Jerry Smith. Staff witness David Schlissel also addresses market power in Arizona electricity markets, and Staff witness Paul Peterson will address the changing market rules being developed by Independent System Operators, the development of Regional Transmission Organizations, and certain Federal Energy Regulatory Commission policies and practices related to market power. Second, I will deal with certain jurisdictional issues raised by Chairman Mundell.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. My testimony is in five sections. After the present section, it has the following sections:

II. Summary and Recommendations.

III. Market Power in Western and Local Electricity Markets.

IV. Certain Jurisdictional Issues.

V. Concluding Remarks.

II. Summary and Recommendations

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON MARKET POWER.

A. I describe problems of market power in both regional and local electricity markets. I recommend that there should be a rebuttable presumption that incumbent utilities and their affiliate generators will have both horizontal and vertical market power when they restructure. I argue that utility systems have traditionally been designed to supply generation on a vertically-integrated basis, and that initially their transmission systems are unlikely to be able to support a robust competitive market, one which must rely on more trading of electricity between service territories. I outline continuing inadequacies in the structure of the Western regional market, but I emphasize the fact that even if there is a *relatively* competitive regional market, the local Arizona market is broken into load pockets that give incumbent generators significant market power. Horizontal market power is a general concern, and in cases of transfer of generation to affiliates, vertical market power is also a concern. As a threshold requirement for restructuring, a utility should be required to demonstrate that it or its generation affiliate or other generator(s) to which it proposes to divest generation assets will be unable to exercise market power. If the utility acknowledge that there will be market power concerns, it should propose appropriate mitigation measures, including enhancements of its transmission system and minimum roles for IPP generation.

Q. PLEASE SUMMARIZE YOUR TESTIMONY ON JURISDICTIONAL ISSUES.

A. I start from the basis that the Commission retains the authority to ensure that generation rates, as well as transmission and distribution rates, are just and reasonable. The Utility Distribution Company (UDC) has an obligation to provide transmission and distribution service, and generation service for its Standard Offer Service customers, at just and reasonable rates. It follows that a UDC should retain its control over the acquisition of electricity for Standard Offer Service customers and should not delegate that control to an affiliate.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO TRANSFER OF GENERATION ASSETS?

A. I have already noted that transfer of generation assets to an affiliate generator in current circumstances would give rise to horizontal and vertical market power concerns. Enhancements are needed to transmission systems in Arizona, and regional power market institutions such as an RTO are not yet ready to adequately monitor the regional, let alone the local, market.

III. Market Power in Western and Local Electricity Markets

Q. PLEASE DEFINE MARKET POWER.

A. Market power is the ability of a single seller or group of sellers of a product or service to influence its price.

The Harm Caused by the Exercise of Market Power

Q. PLEASE DESCRIBE THE HARM THAT CAN BE CAUSED BY MARKET POWER.

A. Suppliers with market power have the ability to raise prices above the levels that would prevail in a competitive market. Such price increases may prevail over periods of time, or they may be relatively short-term price spikes. Pervasive price increases may reflect the inefficiency of suppliers with higher cost structures than would prevail under competitive conditions. They may also simply represent higher profits for suppliers. In either case, consumers end up paying more for the service. In the California electricity crisis, we can see a dramatic instance of this harmful effect on consumers, an effect which was in the tens of billions of dollars.

Q. IF SELLERS RAISE PRICES, WON'T NEW COMPETITORS SOON BE DRAWN INTO THE ELECTRICITY MARKET?

A. No. Firstly, there are effective barriers to entry in electricity markets, at least in the short term. It takes at least two years for new competitors to construct new generation facilities, and it can take much longer to plan, get permits for, and construct new transmission facilities. Other barriers to entry may include bureaucratic obstacles to plant approval, and the difficulty of finding sites with fuel supply and transmission access. Furthermore, as we now know from the California experience, profits from the short-term manipulation of the market can be so large that sellers may not care about competitive entry in the long term. Meanwhile, consumers suffer.

Q. DID THE CALIFORNIA CRISIS REVEAL OTHER POTENTIAL HARMFUL EFFECTS OF MARKET POWER?

A Yes. The exercise of market power in California appears to have exacerbated an underlying problem of shortages of supply, resulting in market disruptions and impairing reliability of supply. In other words, it seems likely that the games played by suppliers resulted in blackouts and brownouts.

Q. CAN MARKET POWER HAVE OTHER HARMFUL EFFECTS?

A. Yes. Sellers with protected positions in a market are less likely to be innovative and responsive with respect to service quality and variety of services. The result is that customers are likely to suffer from reduced service quality and variety, as well as higher prices. One of the arguments in favor of competition in the generation market is that it is likely to lead to the emergence of suppliers that are not only more efficient, but are more responsive to customer requirements in other ways. These developments are less likely to occur in a market in which there is a significant amount of market power.

Types of Market Power

Q. WHAT DIFFERENT TYPES OF MARKET POWER ARE THERE?

A. Broadly, there are two types: horizontal market power and vertical market power. Horizontal market power exists when one or more sellers can directly influence the price of the product or service they are selling. Vertical market power exists when one or more sellers can *indirectly* control the market for a product or service they are selling by influencing the price or availability of a complementary product or service at a different stage of production. For example, a seller of electricity can influence its price in an area if it can restrict access to, or the price of, transmission facilities that competitors need to deliver electricity into that area.

Q. IN THE PRESENT PROCEEDING, WHICH MARKET POWER ISSUES WOULD YOU SUGGEST THE COMMISSION SHOULD ADDRESS?

A. I would suggest that the Commission focus on the *wholesale* market for electricity (the bulk power market). I do not believe the competitiveness of retail access as such is a threshold issue -- it will remain under the primary jurisdiction of the Commission, and can be fostered over the next several years. Regarding the wholesale market, I would distinguish between two kinds of issues -- *regional* and *local*. I would suggest that the Commission should recognize that regional problems are largely beyond its control. They are primarily the province of the Federal Energy Regulatory Commission (FERC). The California authorities also affect the regional market, because that state represents such a large share of the Western market, and its market structure is currently being changed.

Problems in the Regional Market

Q. WHAT KINDS OF REGIONAL PROBLEMS DO YOU HAVE IN MIND?

A. I refer to the degree of competitiveness of Western and Southwestern electricity markets, or, putting it the other way round, their degree of vulnerability to price increases caused by market manipulation and/or tightness of power supplies.

Q. CAN SOME INTERCONNECTED ELECTRICITY MARKETS BE MORE COMPETITIVE THAN OTHERS?

A. Yes. For example, for purposes of exports to California, the regional market faced by Arizona generators, e.g., those in the Palo Verde area, is *relatively* competitive, more so than the Arizona market itself. There are many sellers on the Western electricity grid with access to the California market. They can be expected to vie with each other to keep prices competitive, at least during periods when the system is not suffering from supply shortages or transmission congestion.

Q. DO YOU BELIEVE THE REGIONAL MARKET IS NOW FULLY COMPETITIVE AND LIKELY TO BE STABLE?

A. No, unfortunately it is clear that the regional market is not yet fully competitive. The California crisis showed that the regional market is prone to shortages, and, more fundamentally, that it lacks the necessary institutional and market structures to prevent shortages and deal with market manipulation.

Q. ARE THERE CURRENT DEVELOPMENTS THAT COULD JEOPARDIZE THE DEVELOPMENT OF THE REGIONAL MARKET?

A. Yes. In the wake of the Enron disaster, there have been subsequent discoveries of accounting irregularities in other firms producing and marketing electricity. There is also direct evidence that Enron manipulated the California market, and the suggestion that other companies might have used similar practices. The stock market has responded by slashing the stock prices of the companies involved, and industry sources of capital in credit markets are drying up. These developments are coming at a bad time. Already, the Western independent power producer (IPP) industry was entering what threatens to be a "bust" phase of a boom-and-bust cycle. In 2000 and 2001, high electricity market prices in the West were bad for consumers but good for producers, and there was a construction boom. By the end of 2001, prices were falling and construction plans were being shelved. Now, investors' aversion to risk in the power industry could result in regional shortfalls of capacity if the economy and electricity demand resume their growth during the next few years. The New York Times, in a May 16, 2002 article titled *Power Giants Have Trouble Raising Cash for Plants*, quoted industry experts as having this concern. There is a related concern that transmission construction might also fall short of requirements.

Q. HOW SHOULD THE COMMISSION ADDRESS REGIONAL ISSUES THAT FALL WITHIN FERC'S PURVIEW?

A. I believe that the Commission's primary concern with respect to these regional markets should be to ensure, before it places greater reliance on them, that structures are in place to provide protection for ratepayers and to create and sustain workable competition. Again, putting it the other way round, the Commission should assure itself that there is unlikely to be a recurrence of the market crises of the past two years. Although the Commission has little control over regional markets, it can monitor them to determine if and when an appropriate market structure is in place under the jurisdiction of FERC.

Q. WHAT DO YOU MEAN BY AN APPROPRIATE MARKET STRUCTURE?

A. Usually, an appropriate market structure would be one that includes an effective Regional Transmission Organization (RTO) under the aegis of FERC with the means to actively monitor wholesale regional markets, and identify and deal with market power abuses. The RTO should be able to set transmission rates and require or influence the construction of new transmission capacity to encourage trading. Not least, the RTO should be able, together with Western states, to ensure that policies are in place to avoid a boom-and-bust cycle in the regional electricity market. In the absence of an RTO, a utility seeking to transfer assets should provide a plan as to how these functions will be addressed before the transfer occurs.

Q. ARE APPROPRIATE REGIONAL STRUCTURES IN PLACE TODAY?

A. No. Firstly, FERC is still trying to get to grips with market design issues, as evidenced by the fact that it has issued a Market Design NOPR. Staff witness Paul Peterson will deal with this issue in his testimony. I may add that California, which as noted above is large enough to affect the whole regional market, is proposing new market rules. What we are seeing in the regional energy market is a work in progress.

Q. MEANWHILE, WHAT ROLE SHOULD THE COMMISSION PLAY WITH RESPECT TO REGIONAL MARKETS?

A. With respect to regional markets, I would suggest that the Commission work within the framework of FERC and perhaps other regional entities to create local conditions that support FERC policies, e.g. permitting and encouraging the construction of generation and transmission capacity in Arizona as part of regional electricity system expansion. And the Commission should make its own finding about if and when the regional wholesale market is sufficiently competitive to make it prudent for Arizona to place greater reliance on it.

Q. DOES THE CHAIRMAN'S LETTER OF MAY 14, 2002, REGARDING POTENTIAL MARKET MANIPULATION IN THE WEST AND RELIABILITY OF ELECTRIC SERVICE IN ARIZONA ADDRESS THIS ISSUE?

A. Yes. I note that the Chairman is requesting that "the ACC staff actively monitor FERC's investigation of potential energy market manipulation in the West and make timely summary findings in the ACC generic electric restructuring docket as to the status of FERC's investigation." I would suggest that the Staff's monitoring effort should be oriented toward the future, with a view to determining if and when the regional market is likely to be structured in a manner that avoids electricity shortages and market manipulation going forward.

Market Power in the Arizona Electricity Market

Q. IF THE REGIONAL MARKET IS QUITE COMPETITIVE DESPITE HAVING SIGNIFICANT REMAINING PROBLEMS, IS THE ARIZONA MARKET IN THE SAME SITUATION?

A. No, the Arizona market is significantly *less* competitive than the regional market. Firstly, it is vulnerable to recurrences of regional problems that could result in regional shortages or price spikes. More importantly, however, the Arizona market is limited by transmission constraints that protect local generators against outside competitors. It is therefore less competitive, at least during some seasons and times of day.

Q. PLEASE DISCUSS LOCAL MARKET POWER ISSUES THAT SHOULD BE OF CONCERN TO THE COMMISSION.

A. There are two sets of local issues that are critical in restructuring. One is the adequacy or inadequacy of local transmission and generation capacity to diminish *horizontal* market power in the Arizona market. The other is the problem of *vertical* market power resulting from the ownership of transmission and generation facilities by affiliates of the Utility Distribution Companies (UDCs). The Commission has considerable authority over these two sets of issues.

Q. WHAT ARE YOUR CONCERNS REGARDING THE ADEQUACY OR INADEQUACY OF LOCAL TRANSMISSION AND GENERATION CAPACITY?

A. Data developed by Staff witness Jerry Smith shows clearly that most of Arizona's electricity consumption is in "load pockets" which have limited capability to import electricity and therefore depend on generation *within* the area to meet loads during at least some periods of time. Mr. Smith identifies the Valley area, Tucson and Yuma as load pockets. Tucson Electric Power has stated that it "is constrained relative to imports into the Tucson area...All of TEP's retail load is within the import limited service territory of TEP."

Q. WHAT IS THE SIGNIFICANCE OF THIS DATA REGARDING LOAD POCKETS?

A. This data makes it clear that there is pervasive market power in Arizona. The existence of load pockets means that some generating units within the load pocket must run during at least certain periods of time. The owners of those units, who are mostly the incumbent utilities, can increase prices in these circumstances. Transmission barriers limit the ability of generators from outside the load pocket to compete for customers within the load pocket. Moreover, the California electricity crisis showed clearly that when supplies are tight sellers can manipulate prices.

Q. IS THIS A TEMPORARY OR PERMANENT PROBLEM?

A. Staff witness Smith has pointed out that there is a substantial transmission and generation construction program in Arizona that may alleviate the load pocket problem during the next few years. At some point during that period, I would hope that the Commission can satisfy itself that, with relatively minor exceptions, the wholesale electricity market is ready for competition, provided FERC and other states have done their bit at the regional level.

Q. DOES MR. SCHLISSEL ALSO ADDRESS THE PROBLEM OF MARKET POWER?

A. Yes. Mr. Schlissel provides a more detailed analysis of market power in local wholesale electricity markets.

Q. YOU REFERRED ALSO TO *VERTICAL* MARKET POWER AT THE LOCAL LEVEL. PLEASE DISCUSS THIS PROBLEM.

A. Some of Arizona's UDCs, including APS and TEP, own both transmission and generation. This creates the potential for exercise of *vertical* market power. APS is proposing to transfer generation to an affiliate, PWEC. The Commission should be satisfied that APS is building adequate transmission capacity and making it available to competitors on equal terms, and is not restricting access in a manner that favors PWEC generation. This leads to the issue of a code of conduct between affiliates, which Staff witness Barbara Keene will discuss.

Rebuttable Presumption of Market Power

Q. FROM A REGULATORY STANDPOINT, HOW SHOULD THE ACC APPROACH THE LOCAL MARKET POWER PROBLEM IN ARIZONA?

A. I would suggest that there should be a *rebuttable presumption* of market power. This is the approach adopted in Minimum Filing Requirements that I helped write for the Arkansas Public Service Commission. As one of the participants in the Arkansas proceedings said to me, "The last thing we want to do is go from a situation of regulated monopoly to a situation of *unregulated* monopoly." Attachment A to that commission's Order No. 11, dated June 27, 2000, in Docket No. 00-048-R, Section 4, titled Burden of Proof, reads as follows:

> Given that each electric utility has hitherto been a regulated monopoly supplier of retail electricity services in its service territory, there shall be a rebuttable presumption that each utility and its (marketing) affiliate will be in a position to exercise market power when the Arkansas retail electric market is deregulated and retail open access is introduced.

Q. PLEASE EXPLAIN THIS PROVISION AS IT RELATES TO *HORIZONTAL* MARKET POWER.

A. The transmission systems of most traditional electric utilities, including Arizona's electric utilities, were not designed to be able to bring in large amounts of power from other areas. Apart from situations in which utilities relied upon supplies from remote power plants in which they had ownership shares, transmission links were mostly built to enhance reliability and allow for limited exchanges of economy energy between utilities. They were not built to allow for extensive trading and purchases from independent power producers in a regional market framework.

Q. SHOULD THE REBUTTABLE PRESUMPTION OF MARKET POWER ALSO APPLY TO *VERTICAL* MARKET POWER?

A. Yes. The manner in which vertically-integrated utilities were planned and operated gives rise to a likelihood of vertical market power. This is well expressed in a July 17, 1998 order of the New York Public Service Commission, *Order Adopting a statement of policy regarding vertical market power in a restructured electric industry* in Case No. 96-E-0900, et al.). The statement reads in part:

> In creating a competitive electric market, the Commission has viewed divestiture as a key means of achieving an environment where the incentives to abuse market power are minimized...
>
> Vertical market power occurs when an entity that has market power in one stage of the production process leverages that power to gain advantage in a different stage of the production process. A transmission and distribution company (T&D company) with an affiliate owning generation may, in certain circumstances, be able to adversely influence prices in that generator's market to the advantage of the combined operation. Two examples are given below.
>
> -- The affiliate's generator is located in the same market as the T&D company. The T&D company has an incentive to make entry by generators into its own territory difficult, and therefore, expensive for a new entrant by either delaying or imposing unrealistic interconnection requirements, and thereby raising prices in the region...

-- The affiliate's generator is on the high cost side of a transmission constraint and the T&D company has the ability to influence the transmission constraint. The T&D company has the incentive to retain the constraint to keep the market price high on the high cost side of the constraint…

To guard against undesirable incentives, a rebuttal (sic) presumption will exist for the purposes of the Commission's…review of the transfer of generation assets, that ownership of generation by a T&D company affiliate would unacceptably exacerbate the potential for vertical market power…

Q. INCIDENTALLY, DOES APS SHARE THE VIEW THAT UTILITY SYSTEMS WERE TRADITIONALLY PLANNED IN A MANNER THAT IS NOT CONDUCIVE TO THOROUGHGOING COMPETITION?

A. Yes, I believe it does. Mr. Jack Davis stated as much in his Rebuttal Testimony in Docket No. E-01345A-01-0822, filed on April 22, 2002, on page 5. He said that it would be "misplaced and premature" to put trust in the wholesale markets "prior to the implementation of the very structural reforms and infrastructure upgrades cited by Staff as essential to the efficient working of that same market." Likewise, APS witness Mr. John Landon, in his Rebuttal Testimony in the same docket, filed on April 22, 2002, at page 19, emphasizes the current shortfall of transmission capacity:

(T)he amount of transmission resources necessary to support fully competitive wholesale markets will necessarily be significantly greater than those needed for a regulated utility service from a vertically integrated system. Thus, it is hardly

> surprising that transmission in Arizona is not sufficiently robust to allow an immediate shift to fully competitive wholesale markets."

And APS witness Cary Deise, in his Rebuttal Testimony of April 22, 2002 in the same docket, at page 3, criticizing what he calls "errors" made by certain intervenor witnesses relating to APS' transmission system and its capabilities, says the following:

> The system simply was not designed, nor should it have been designed, with large amounts of surplus capacity to accommodate unplanned generation additions (competitive or otherwise) within a relatively concentrated area, let alone allow unconstrained access to all of APS' loads or to loads in other regions or states.

Q. THESE STATEMENTS MADE BY APS WITNESSES ARE INTENDED TO SHOW THAT IT IS UNWISE FOR APS TO SWITCH IMMEDIATELY TO COMPETITIVE BIDDING. IS IT APPROPRIATE TO RELY ON THESE STATEMENTS AS SUPPORT FOR THE VIEW THAT THE ARIZONA POWER MARKET IS VULNERABLE TO THE EXERCISE OF MARKET POWER BY INCUMBENT UTILITIES?

A. Yes. This is the other side of the same coin. The basis of APS's proposals for a variance and PPA is that the wholesale power market is too thin and too volatile.

Q. CAN A CODE OF CONDUCT PREVENT THE EXERCISE OF VERTICAL MARKET POWER?

A. While it is better to have a market structure in which participants' incentives are aligned with the public interest – as is supposed to be the case in a workably competitive market -- an effective code of conduct or affiliate interest rules can militate against this anti-competitive coordination of transmission and generation. Codes of conduct are discussed in the testimony of Staff witness Barbara Keene.

Q. WILL THE LARGE AMOUNTS OF GENERATION OWNED OR CONTROLLED BY PWCC OR OTHER UTILITY-AFFILIATED GENERATORS PRESENT A MARKET POWER PROBLEM?

A. Construction of new IPP generation and increases of transmission capacity will tend to reduce the market power of incumbent generators. On the other hand, I note that PWEC is undertaking a billion-dollar generation construction program, which will, other things being equal, tend to increase its market power. Whether on balance a significant market power problem will still exist remains to be seen. Probably the most significant mitigating factors in both the local and regional markets will be the adequacy of generation capacity and a coordinated expansion of the transmission grid.

Quantitative Tests for Market Power

Q. ARE THERE QUANTITATIVE TESTS THAT CAN BE USED TO TEST FOR HORIZONTAL MARKET POWER?

A. Yes. It is important to note, however, that these tests are not definitive -- they provide at best an indication of market power. Moreover, these tests can fail to capture the specific structure of the electric generation industry, dependent as it is on a local and regional combination of power plants and transmission lines, the need to instantaneously satisfy fluctuating demands for electricity, and the institutional structure of the markets for energy and ancillary products. The specifics of the industry have led to exercises of market power when they were not expected, as in California during 2000 and 2001. And this experience has led to changes in the tests that are applied.

Q. HOW HAVE THESE ADMITTEDLY IMPERFECT TESTS FOR MARKET POWER EVOLVED IN RECENT YEARS?

A. Up until recently, the FERC was relying on rules of thumb and traditional market power tests derived from the *Horizontal Merger Guidelines* of the U.S. Department of Justice and Federal Trade Commission. These relied primarily on structural analysis of suppliers' market shares, using quantitative measures like the HHI index to measure market *concentration*.

Q. PLEASE DESCRIBE THE HHI INDEX.

A. The Herfindahl-Hirschman Index or HHI is computed as the sum of the squares of the percentage market shares of suppliers of a relevant market. The higher the index, the greater the degree of concentration and the potential for market power. For example, if there were five suppliers --including some large ones -- with market shares of 50%, 30%, 10%, 5% and 5% respectively:

$$HHI = 50^2 + 30^2 + 10^2 + 5^2 + 5^2 = 2500 + 900 + 100 + 25 + 25 = 3,550$$

An index of 3,550 shows a high degree of concentration. If the market had five *equally-sized competitors*, each with a market share of 20%, the index would be lower:

$$HHI = 20^2 \times 5 = 400 \times 5 = 2,000$$

And if the market had *ten* equally-sized competitors, each with a market share of 10%, the index would be even lower:

HHI = $10^2 \times 10 = 100 \times 5 = 1,000$

What these three examples show is that it is not only the *number* of companies that reduces the HHI, it is also the absence of one or more companies with *large shares* of the market. The Texas restructuring legislation contains an upper limit of 20% market share for any one supplier, and the Arkansas Minimum Filing Requirements use as a threshold test a market share of 25% for a utility and its marketing affiliates.

Q. WHAT ARE THE CRITICAL LEVELS OF THE HHI?

A. The U.S. Department of Justice and Federal Trade Commission "broadly characterize" markets as unconcentrated if the HHI is below 1,000, moderately concentrated if the HHI is between 1,000 and 1,800, and highly concentrated if the HHI is above 1,800. Note that the first two examples given above, in which there were five competitors, would be "broadly characterized" as highly concentrated, including the second example in which the five competitors were equally sized. The third example, however, with ten equally sized competitors, would be on the borderline between moderately concentrated and unconcentrated. The screen in the Arkansas Minimum Filing Requirements provides that a utility shall file a strategic behavior analysis (see below) if it controls at least 25% of a market *and* the market's HHI exceeds 1,000. It is difficult to apply the HHI index to electricity markets, because there are often disputes over the geographical extent of the market which involve making judgements about the availability and price of transmission. Moreover, since the HHI does not account for the overall tightness of the market, it is not an ideal measure.

Q. HAS FERC'S APPROACH CHANGED TO TAKE THIS ISSUE INTO ACCCOUNT?

A. Yes. FERC has introduced a new structural test, which it calls the "pivotal supplier" or Supply Margin Assessment (SMA) test. This test takes into account not only the sizes of suppliers, but the tightness of the market in terms of reserve margin, something that appears to have been a major factor in the manipulation of markets in California during the past two years. The pivotal supplier test is described and applied to Arizona in the testimony of Staff witness David Schlissel.

Q. WHAT OTHER TESTS HAVE BEEN APPLIED?

A. Another major step in regulatory thinking on the subject of market power has involved recognition of the games that suppliers can play, particularly if they own several generation plants. These games are called "strategic behavior" and include strategic bidding or pricing of generation and strategic withholding of generation from the market. Even though a market appears to have a relatively low level of concentration according to the HHI, computer modeling of the system under alternative assumptions regarding pricing and withholding can reveal opportunities for market manipulation by large sellers.

Q. IS THE EXERCISE OF MARKET POWER NOW ENTIRELY PREDICTABLE AND AVOIDABLE?

A. No, I believe it would be optimistic to believe that FERC is now completely on top of the problem. Putting it differently, it does not seem that market power will disappear when some new market structure is designed and implemented. Anjali Sheffrin, the director of market analysis at the California ISO, says that energy markets remain vulnerable to manipulation. Marketers "will keep testing us any way they can, in big ways and small...Unless we are more diligent, we could have the same kind of crisis all over again." (New York Times, May 12, 2002, first business page.)

Q. WHAT IS THE SOLUTION TO THIS RECURRING PROBLEM?

A. There will no doubt be many market design fixes to problems as they emerge. The overarching solution, however, is institutional. It is essential to have an RTO with market monitoring responsibility, adequate capability to exercise that responsibility, and the authority to apply sanctions and penalties. In the New York Times article referred to above, an energy trader is quoted as saying, "Energy trading is a football game; it ain't bridge...If you want a nice game because electricity is an important public good, then set up a nice game." Pursuing this sports metaphor, when we reject a "nice" regulated utility game for electricity in favor of the rough and tumble of competition, we must recognize that electricity markets need market monitors as much as football games need referees.

IV. Certain Jurisdictional Issues

Q. CHAIRMAN MUNDELL HAS INCLUDED JURISDICTIONAL CONCERNS IN THE LIST OF THRESHOLD ISSUES. PLEASE COMMENT ON THE ISSUE OF JURISDICTION.

A. If an Arizona UDC transfers generation assets to an affiliate generator or divests them to a non-affiliated generator, the presumption is that the Commission will effectively lose jurisdiction over those assets. This is because the Commission does not have jurisdiction over wholesale sales. FERC would acquire jurisdiction over the buyback of power by the UDC from the affiliated or non-affiliated generator.

Q. DOES THE LOSS OF JURISDICTION BY THE ACC INVOLVE A RISK TO UDC RATEPAYERS?

A. Yes. The Commission would lose the ability to set generation rates in the traditional manner, on the basis of cost of generation including fair rate of return. If the local electricity markets are not yet workably competitive, the buyback of power or the purchase of power from other generators might be at prices in excess of cost.

Q. HOW HAVE OTHER COMMISSIONS DEALT WITH THIS RISK?

A. Nevada and New Mexico have delayed the transfer of generation assets until such time that the state authorities are satisfied that the local and regional generation markets are workably competitive and effectively regulated by FERC and a regional RTO. Virginia is requiring that generation assets be transferred to a different division of the same corporate entity as the UDC. Montana has apparently been able to argue that the transfer of generation assets carried with it an obligation to sell power back to the utility at cost, but this appears to be a special case.

Q. ARE THERE OTHER WAYS IN WHICH THIS RISK CAN BE AVOIDED?

A. Perhaps the jurisdiction problem can be satisfactorily overcome if the transfer of assets is coupled with a reasonable buyback agreement or Purchased Power Agreement (PPA), effective until the Commission makes a determination that the local and regional markets are workably competitive and effectively regulated by FERC and a regional

RTO. APS may argue that it has already proposed a reasonable PPA; however, Staff believes that APS's proposal is not appropriate.

Q. EVEN IF THE POWER MARKETS ARE EFFECTIVELY COMPETITIVE AND WELL-REGULATED, IS THERE A DANGER THAT AN AFFILIATE GENERATOR COULD BE FAVORED BY A UDC?

A. Yes. Staff witness Barbara Keene has proposed a code of conduct to help mitigate this problem. The Commission could and should require that a UDC does not favor an affiliate. Competitive bidding rules, and/or rules regarding the selection of suppliers under bilateral contracts, can cover this situation, either as part of or in addition to a code of conduct. Regulations of this kind would seem to remain within the Commission's jurisdiction.

Q. THE UDC RETAINS THE OBLIGATION TO PROVIDE SERVICE, INCLUDING STANDARD OFFER SERVICE. DOESN'T THIS IMPOSE ON THE UDC THE DUTY TO ACQUIRE POWER IN A WAY THAT WILL ENSURE THAT RATEPAYERS WILL HAVE JUST AND REASONABLE RATES?

A. Yes. Staff witness Matthew Rowell will address this issue.

Q. DOES THIS ISSUE HAVE JURISDICTIONAL RAMIFICATIONS?

A. Yes. It suggests that the Commission retains, or should retain, jurisdiction over the prudence of UDC's acquisition of power to serve standard offer customers. The Commission should be able to satisfy itself that generation rates for standard offer service are just and reasonable.

Q. HOW CAN THE COMMISSION DO THIS IN THE CASE OF POWER ACQUIRED UNDER FERC-REGULATED CONTRACTS OR FROM FERC-REGULATED MARKETS?

A. Firstly, it seems that the Commission should ensure that acquisition *is by the UDC itself* and is not delegated to an affiliate. The Commission can then determine that purchase power agreements are reasonable from a ratepayer standpoint. (I believe the Pike County case gives some authority to state commissions in circumstances of this kind.) Secondly, the Commission should establish competitive acquisition procedures for the UDC, as I suggested earlier.

VII. Concluding Remarks

Q. WHAT DO THESE VARIOUS PRINCIPLES MEAN FOR ARIZONA?

A. I am concerned about the transfer of utility assets to a utility affiliate. I believe that the transfer would result in a loss of Commission jurisdiction over utility generation assets. I believe that the Commission should ensure that the market is ready to support competition before taking such an irrevocable step. The Commission can do this by requiring the utilities' to file market power studies before transferring generation assets. To do otherwise risks premature restructuring.

Q. WHAT IS YOUR PRIMARY CONCERN ABOUT PREMATURE RESTRUCTURING?

A. In a nutshell, my concern is market power. This is turning out to be a far more pervasive problem around the country than it was expected to be.

Q. IN ITS REBUTTAL TESTIMONY IN DOCKET NO. E-01345A-01-0822, FILED ON APRIL 22, 2002, APS ARGUED THAT ITS FINANCIAL ARRANGEMENTS DEPEND ON THE TRANSFER OF ASSETS TO PWEC, AND THAT IT WOULD BE UNFAIR FOR THE COMMISSION TO HAVE A CHANGE OF HEART AT THIS TIME. DO YOU AGREE?

A. The Company's argument misses the underlying point. What is involved here is not a change of heart but a change of circumstances. It is quite reasonable for the Commission to review certain threshold issues and, if necessary, change one or more elements of its restructuring plan, which assumed the existence of a competitive wholesale market.

Q. APS CLAIMS THAT THE TRANSITION TO COMPETITIVE MARKETS HAS BEEN UNDER WAY FOR YEARS AND IS PROCEEDING SUCCESSFULLY. DO YOU AGREE?

A. No. The difficult parts of the transition have not yet taken place. While Arizona's retail markets have in theory been opened to competition, there are as yet no retail competitors in place, and retail markets remain the domain of regulated, vertically-integrated utilities. Tough issues, such as the breakup of large generators to prevent market power, have not been addressed. And the regional RTO arrangements are not in place. In fact, the reason why the situation is stable is that, as far as retail customers are concerned, nothing has changed.

Q. IN ITS MOTION FOR DETERMINATION OF THRESHOLD ISSUE, APS SAID THAT "THE THRESHOLD POLICY CHOICE IS STRAIGHTFORWARD – DO

WE CONTINUE TOWARDS RETAIL ELECTRIC COMPETITION OR DOES THE COMMISSION REVERSE COURSE AND RETURN TO TRADITIONAL COST-OF-SERVICE MONOPOLY REGULATION." DO YOU AGREE WITH THE WAY IN WHICH APS HAS FRAMED THE THRESHOLD ISSUE?

A. No. In presenting the issue as an either/or one, APS has not mentioned the more important issue that it behooves the Commission to address in light of the slow development of the competitive market in Arizona and the region. Staff is not proposing at this point that the Commission should reverse course. Staff is instead suggesting that the Commission ensure that the appropriate steps are taken at the appropriate times. To allow asset transfer to occur before a workably competitive market is in place may actually impede the development of viable competition. For these reasons, it is appropriate for the Commission to examine the reasonableness of asset transfer in light of the potential for market power and other potential market manipulation.

Q. DOES THAT COMPLETE YOUR TESTIMONY?

A. Yes, thank you.

EXHIBIT NHT-1

NEIL H. TALBOT

Economic & Financial Consultant

Education

M.S.F. Finance, Boston College, 1992
M.A. Economics, Cambridge University, England, 1968

Employment History

1995 - Economic and financial consultant to Synapse Energy Economics
1980-1994 Tellus Institute, Boston, Mass. Member of Energy Group responsible for utility economic, financial and regulatory analyses.
1973-1979 Arthur D. Little, Inc., Cambridge, Mass. Member of Managerial Economics Section responsible for public utility economic and planning studies and energy economics.
1968-1973 The Economist Intelligence Unit Ltd., London, England. Project leader of Caribbean economic development studies; research and consulting on industrial and utility economics.

Summary of Relevant Experience

Neil Talbot is an economic and financial consultant to Synapse Energy Economics, Inc. He has masters degrees in economics and finance from Cambridge University and Boston College respectively. He has had 32 years' experience as a consultant focusing primarily on utility company economic, financial and regulatory issues with the Economist Intelligence Unit of London, Arthur D. Little, Inc. of Cambridge, Mass., Tellus Institute of Boston, Mass., and Synapse Energy Economics, Inc. He has prepared a wide range of studies and testimony on utility planning, rate of return, mergers and acquisitions, incentive rates, financial modeling of utilities under alternative rate scenarios, valuation of utility assets and evaluation of utility projects and contracts.

In recent years, Mr. Talbot has focused on the new issues facing the electric utility industry. He is currently a member of the Synapse Energy Economics team retained by the Utah Committee of Consumer Services to review the proposed reorganization of PacifiCorp. He has been a consultant to the Arkansas Public Service Commission on the restructuring of the electric utility industry; his most recent assignments have been to advise on the rate-making treatment of the proposed merger (now cancelled) between Entergy (parent of Arkansas Power &

Light Co.) and FPL Corp., and to draft a market power rule and filing guidelines which were recently submitted to the commission. Articles written by Talbot include *The Right Path for Electricity Restructuring: 10 Guidelines for State Legislation* (The Electricity Journal, January/February 1999) and *A Stranded Cost Recovery Alternative* (Electricity Journal, May 1998).

Mr. Talbot was retained in 1999 by the Utah Committee of Consumer Services to review the financial aspects of the proposed acquisition of PacifiCorp by ScottishPower, and by the Maine Office of Public Advocate to review the proposed acquisition of CMP Group by Energy East. On behalf of the Attorney General of Washington State, he testified in 1996 on the financial impacts of the proposed merger of Puget Sound Power & Light Company and Washington Energy Company. His focus was on financial impacts of the merger and he developed and applied a corporate financial model to the utilities.

Mr. Talbot has testified frequently on cost of capital for regulated utilities. In 1995, he presented testimony on behalf of the Illinois Citizens Utility Board (CUB) on the cost of capital of Northern Illinois Gas Company. His testimony also opposed the company's proposed incentive regulation plan, which the company withdrew during the proceedings. Also for CUB, he testified on the cost of service and cost allocations of Commonwealth Edison Company.

In 2000, Mr. Talbot assembled a Synapse Energy Economics team for the Vermont Department of Taxes to prepare valuations of the Hydroelectric Generating Facilities on the Connecticut and Deerfield Rivers. In the 1990s, Talbot appraised various hydroelectric power plants for towns in Vermont. He evaluated purchased power contracts of Public Service Company of New Hampshire and Bangor Hydro Electric in 1994 and 1995 respectively.

In other rate work, Mr. Talbot has reviewed the incentive regulation plan (Alternative Rate Plan) for Central Maine Power Company and the Alternative Marketing Plan of Bangor Hydro, in testimony before the Maine Public Utilities Commission. He is the author of an AARP position paper entitled *Evaluating Price Cap Proposals in the Electric Utility Industry*. In 1998 he completed a *Sunset Review of the Energy Center of Wisconsin.*

Selected Testimony

Agency	Case or Docket No.	Date	Topic
Maine Public Commission	99-411	Sept. 1999	Acquisition of Central Maine Power Utilities by Energy East
Utah Public Commission	98-2035-004	June 1999	Acquisition of PacifiCorp (UP&L) Service by Scottish Power
Arkansas Public Commission	97-451-U	May 1998	Testified as Staff Expert in Electric Service Industry Restructuring Proceeding
Arkansas Public Commission	96-360-U	July 1997	Changes in Retail Rates and Transition to Service Competition Plan
Washington U.T.C.	UE-960195	Sept. 1996	Proposed Merger of Puget Sound P&L and Washington Natural Gas Co.
Maine Public Utilities Commission	96-187	Aug. 1996	Proposed Interim Competitive Transition Charge Tariff of Central Maine Power Co.
Illinois Commerce Commission	95-219	Nov. 1995	Incentive Regulation and Rate of Return for Northern Illinois Gas Company
Maine Public Utilities Commission	95-901	April 1995	Evaluation of Purchased Power Contract Buyout Proposals of Bangor Hydro
California Public Utilities Commission	A.93-12-029	Sept. 1994	Performance Based Ratemaking for Southern California Edison Company
N. Hampshire Public Utilities Commission	93-179	June 1994	Eval. of proposed buyouts by Public Service Company of New Hampshire of long-term purchased power contracts
Illinois Commerce Commission	94-0065	June 1994	Division among customer classes of an increase (or decrease) in revenue requirements for Commonwealth Edison Company, focusing on cost-of-service studies, both marginal and embedded
Kansas Corporation Commission	176,716U	Oct. 1991	Fair rate of return for KPL's Kansas gas operations

Kansas Corporation Commission	172,745-U 174,155-U	Jan. 1991	Proposed merger of Kansas Gas & Electric Company and Kansas Power & Light Company
New Hampshire Public Utilities Commission	DF 89-085	July 1990	Assessment of Eastern Utilities Associates' Plan to acquire UNITIL Corporation
New Hampshire Public Util. Com.	DR-89-244	March 1990	Rate impact of Northeast Utilities take-over of Publ. Serv. Co. of N.H.
Pennsylvania Public Utility Commission	R-891364	Oct. 1989	Fair rate of return and financial impact of rate recommendations on Philadelphia Electric Company
West Virginia P. S. Com.	Case No. 89-173-E-GI	Aug. 1989	Annual fuel review of Appalachian Power Company
Connecticut D. P. U. C.	89-02-16	June 1989	Fair Rate of Return and Rate Design for Connecticut Water Company
New York Public Service Commission	29484 and 88-E-084	July 1988	10-Year Rate Plan of Long Island Lighting Company
Public Service Commission of Utah	87-035-27	Apr. 1988	Effects of the Proposed Merger on UP&L's Energy Balancing Account and on Its Financial Sit. and Cost of Capital
New Mexico Public Service Commission	1811	Jan. 1988	Fair Price for Coal Resources
Public Service Com. of Indiana	38045	Nov. 1986	Evaluation of a power plant for Northern Indiana Public Service Company
Public Service Commission of Maryland	8522	July 1986	Management Audit of Potomac Electric Power Company's Fuel Procurement Practices
West Virginia Public Service Commission	86-081-E-GI 86-082-E-GI	May 1986	Economic Analysis of Pumped Storage Facility
Missouri Public Service Commission	ER-85-128 EO-85-185 EO-85-224	June 1985	The Financial Impact of Alternative Rate Treatments of Wolf Creek on Kansas City Power & Light Company
State Corporation Commission of the State of Kansas	120-924-U 142-098-U 142-099-U	April 1985	Concerning Wolf Creek Fuel Procurement and Nuclear and Other Fuel Costs

State of Connecticut D. P. U. C.	84-02-09	June 1984	Fair Rate of Return for Connecticut Natural Gas Company
Public Service Commission of Utah	80-035-17	Jan. 1981	Long-range Forecast: Electric Energy Requirements and Peak Demand
Ohio Power Siting Commission		July 1978	CAPCO Power Pool Load Forecast
Idaho Public Utilities Commission		March 1976	Evaluation of Pioneer Power Plant

Consulting, Research & Papers

Ongoing	Member of Synapse Energy Economics team evaluating PacifiCorp reorganization proposals
1996-2001	Consultant to the Arkansas Public Service Commission on electric utility industry restructuring and competitive retail access.
1996-2000	Consultant to New Jersey Division of Ratepayer Advocate on electric utility industry restructuring and competition, working regularly in client's office as staff consultant drafting position papers
January 1999	*The Right Path for Electricity Restructuring: 10 Guidelines for State Legislation*, Electricity Journal, Vol.12, No. 1
May, 1998	*A Stranded Cost Recovery Alternative*, Electricity Journal, Vol.11, No. 4
October, 1996	*A Consumer's Skeptical Perspective on Multi-Year Price Cap Plans*, Presentation to Washington, D.C. Conference on *Performance-Based Ratemaking for Electric & Gas Utilities* (Int. Bus. Communications)
August, 1996	*Evaluating Price Cap Proposals in the Electric Utility Industry*, published by American Association of Retired Persons.
July, 1996	*Appraisal of New England Power Company's Moore Station*, a report for Town of Waterford, Vermont
February, 1996	Consultant of Pennsylania Office of Consumer Advocate on Multi-Year Rate Plan of Pennsylvania Power Company
1995	Consultant to City of Wynnewood, Oklahoma, on Long-Term Power Contract with Oklahoma Municipal Power Assoc.
December,	Support for Great Bay Power Corp. with Regard to Cost of Equity

1995	Capital in its Cost-of-Service Filing with F. E. R. C.
February 1995	Comments on Retail Competition in the Electric Power Industry Filed with New Hampshire PUC on Behalf of the Office of the Consumer Advocate
December 1994	Assistance on public utility holding company and diversification proposal of Pennsylvania Power & Light Company
November 1994	Preparation of Comments on Electricity Competition filed with the Pennsylvania PUC by the Office of Consumer Advocate
1992-1993	Co-ordinator of Energy and Environmental Alternatives Planning Assistance Program - Africa. For Stockholm Environment Institute.
1993:	*Zambia: Resuming the Energy Transition.* A report to: Zambia Department of Energy. Co-author. For Stockholm Environment Institute, funded by Swedish International Development Agency.
1994:	*Zimbabwe: Energy End-Uses and End-Use Efficiency.* A report to: Zimbabwe Department of Energy. For Stockholm Environment Institute and Swedish International Development Agency. Co-author.
Oct. 1993	*Financial Economics and Renewable Energy*, presented at: NARUC-DOE National Conference on Renewable Energy, Savannah, Georgia, Oct. 3-6.
July 1992	*Integrated Energy - Environment Planning: Experiences from the United States and Africa*, paper presented with Michael Lazarus, at South African Energy Policy Research and Training Project Workshop, Cape Town.
December 1991	Appraisal of Harriman Hydroelectric Plant of New England Power Co. A report to Town of Whitingham, Vermont. Principal author. 89-047.
Jan.-June 1991	U.S. Agency for Int. Development. Senior Econ. for energy price reform studies for Romania. Provided advice to government regarding energy price reform, energy planning and environmental impacts.
July 1977	*Management Effectiveness and Operating Efficiency of Kansas Gas and Electric Company*, a report to the Kansas Corporation Commission. Co-author.
Feb. 1976	*Idaho Power Company's Need for Additional Generating Capacity*, a report to Idaho Public Utilities Commission. Principal investigator.
Apr. 1974	*Inflation and Economic Growth in the U.S. Virgin Islands*, a report to the Legislature of the U.S. Virgin Islands. Principal investigator.
Jan. 1974	*A Study of International Inflationary Trends, with Special Emphasis on Algeria*, a report to the Algerian Government. Co-author.

Sept. 1973	*Long Term Load Forecast*, a report to Potomac Electric Power Co. Author.
Oct. 1976	Speech on *Load Forecasting for Electric Utilities* published in Proceedings of Need for Power Conference, Columbus, Ohio.

Professional Societies

Member, American Economic Association
Member, Financial Management Association
Member, National Association of Business Economists

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.)	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.)	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.)	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES AND COMPLIANCE DATES.)	DOCKET NO. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.)	DOCKET NO. E-01933A-98-0471

DIRECT

TESTIMONY

OF

PAUL R. PETERSON

SYNAPSE ENERGY ECONOMICS, INC.

APPEARING ON BEHALF OF UTILITIES DIVISION

MAY 29, 2002

Table of Contents

List of Attachments

I. QUALIFICATIONS

Q. Please state your name, business position and address.

A. My name is Paul R. Peterson. I am a senior associate with Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, Massachusetts 02139.

Q. Please describe your educational and occupational background.

A. I have twenty-two years of experience with energy efficiency policy issues through work with the University of Vermont Extension Service, the Vermont Public Service Board, and, most recently, ISO New England, the operator of the regional electric grid for New England. Over the last 7 years, I have worked on electric restructuring issues directly related to the six New England states, regional wholesale power markets, and Federal Energy Regulatory Commission ("FERC") initiated proceedings. I have a BA from Williams College and a Juris Doctor degree from Western New England College School of Law. My qualifications are described in detail in Exhibit PRP-1.

II. INTRODUCTION AND RECOMMENDATION

Q. What is the purpose of your testimony?

A. My testimony identifies critical structures and rules that are necessary to minimize market manipulation and exercises of market power in restructured electric markets. Although problems in California's wholesale markets have garnered most of the headlines, there have been significant problems in the New York, New England, and PJM markets due to market design flaws and the abusive behaviors of market participants. The consequences of many of these behaviors have been unreasonably high wholesale market prices that can translate into higher costs for consumers. My testimony supports the testimony and recommendations of Staff witnesses, including the testimony of Mr. Schlissel and Mr. Talbot, by providing additional information for the Arizona Corporation Commission ("Commission") to consider in the instant docket.

Q. Please summarize your recommendations to the Commission as they pertain to this Docket.

A. The Commission should proceed cautiously with restructuring in Arizona in light of the significant problems that have been experienced in competitive, bid-based wholesale markets around the country. Until specific structures such as RTOs and well-designed markets that are subject to appropriate monitoring and mitigation oversight are established and are demonstrated to be effective, Arizona electricity consumers will be exposed to the risk of market manipulation, abuse, and gaming that may lead to requests for sudden and dramatic increases in retail electricity prices. Under current market models, the Commission will have little immediate recourse other than to grant the price increases, and then petition the FERC for prospective changes to avoid future high prices. My testimony supports Staff's general recommendation that if APS is confident that the transfer of its assets is the best course of action at this time, then it is appropriate to assign to APS the financial risks associated with such a decision.

III. DISCUSSION

Q. What guidance has the FERC provided regarding market monitoring in wholesale electric markets?

A. FERC's guidance has evolved over the years in response to the events that have occurred in wholesale electricity markets. In the mid-1990s, in Orders 888 and 889, the FERC required companies that sought market-based rates to file studies documenting the likelihood of market power issues in the wholesale market in which they intended to operate, and to file plans for addressing any potential exercises of market power. As Independent System Operator ("ISO") administered wholesale markets were implemented in the late-1990s, market monitoring requirements and activities expanded in response to the discovery of market design flaws and the experience of market abuses. In a series of Orders on RTO formation beginning in July of 2001, the FERC has initiated proceedings and provided extensive guidance and recommendations on many design elements of wholesale bid-based markets. In November 2001, FERC announced a new "test" (the supply margin assessment or pivotal test) that companies seeking market-based rates must satisfy. In March 2002, FERC provided the first outline for standardization of RTOs and market designs; a process that FERC believes will assist a rapid implementation of RTO structures. The days of "open architecture" may have passed.

Q. What do you mean by "open architecture"?

A. Until last summer, the FERC had encouraged transmission owning entities to file RTO proposals that meet the four characteristics and eight functions specified in Order 2000[1] through any business structure, market design, and transmission tariff that was reasonable and likely to be effective; the shorthand term for this was "open architecture". In its numerous Orders on RTO filings of July 12, 2001, the FERC emphasized that the time for experimentation was over. Experience with ISO business structures, market designs, and transmission tariffs had established preferred approaches or "best practices" that should become standards for RTOs. Subsequently, FERC has announced several initiatives to develop standard designs and processes for wholesale markets, transmission tariffs, interconnection rules, and market power tests. While not explicitly repudiating the "open architecture" concept, FERC appears to be favoring proven approaches over untested or innovative ideas.

Q. What are the implications for the development of RTOs in the Western Interconnection?

A. It is likely that RTO proposals will need to conform to the standardization process that FERC is conducting. The design of wholesale electric markets, including the monitoring and mitigation functions for those markets, will need to be consistent with the results of FERC's NOPR proceeding which is scheduled for this summer and fall. The same is likely to be true for wholesale tariffs, interconnection rules,

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1 The four characteristics are (1) independence from market participants, (2) appropriate scope and configuration, (3) operational authority, and (4) short-term reliability. The minimum functions pertain to (1) transmission service and tariff, (2) congestion management, (3) parallel path flow, (4) ancillary services, (5) transmission availability information, (6) market monitoring, (7) transmission planning and expansion, and (8) interregional coordination. Regional Transmission Organizations, Order No. 2000, 89 FERC ¶ 61,285 (December 20, 1999).

and a host of other procedures both large and small. All the current RTO filings before the FERC will probably need substantial modification.

Q. What have been the experiences in bid-based wholesale markets?

A. I have excluded California from my discussion because its problems have been well publicized and analyzed, and because its market structure was unique. Less well known are the numerous design flaws and indications of anti-competitive behavior that have resulted in significant price distortions in all of the Northeast markets. PJM has had problems with its capacity cost-allocation system, New York has had problems with its reserve markets, and ISO-NE mitigated bids in its Installed Capacity market (before filing to abolish it). All three of the Northeast ISOs have experienced enormous variances in energy bids under certain circumstances and they all currently have $1,000 bid caps in place. Independent studies of PJM and New England suggest that prices average 5 – 20 percent above cost.

Q. Please describe the extent of market monitoring and mitigation incorporated in early ISO filings.

A. New England provides a good case study because it filed for market-based rate authority subsequent to California and PJM, but before New York. In December 1996, the New England Power Pool ("NEPOOL") filed for market-based rate authority and the creation of an Independent System Operator ("ISO-NE") to dispatch the bulk power system and administer the new bid-based markets. New England had been operated for over twenty-five years as a tight power pool with centralized dispatch and a shared-savings mechanism to facilitate least-cost resource utilization. NEPOOL's filing was designed to retain most of the system operating procedures developed over the preceding years and to substitute a bid-based dispatch for the existing cost-based dispatch.

Q. How did NEPOOL address issues about market power?

A. As part of its overall filing, NEPOOL included a study that determined that congestion problems were rare in New England, except for certain load pockets during times of seasonal (summer) high demand. Based on that study, NEPOOL initially proposed minimal market monitoring activities with no specific mitigation procedures. Other parties, including the New England Conference of Public Utilities Commissioners ("NECPUC"), challenged NEPOOL's rosy assessment and asked FERC to require NEPOOL to be more proactive. In a June 1997 Order approving NEPOOL's overall plan, FERC directed NEPOOL, the just-formed ISO-NE, and NECPUC to engage in discussions to create a specific market monitoring and mitigation plan and to file it with the FERC.

Q. What was the result of this effort?

A. Over the next year, the parties engaged in a collaborative process that resulted in Market Rule and Procedure17 ("MRP 17", attached as Exhibit PRP-2), which FERC approved in November 1998 and further modified in April 1999 when it gave final approval for the implementation of market-based rates. Market Rule 17 included specific procedures for addressing congestion due to reliability concerns (reliability-must-run units) and a separate section for evaluating bids that deviate from competitively established levels. It also established mitigation options and referenced penalty and sanction options that could be applied for improper behavior. MRP 17 authorized ISO-NE to collect cost data from market participants and required ISO-NE to file monthly, quarterly, and annual reports with Federal and state regulators, as well as making redacted versions available to the public.

Q. Why is MRP 17 important to this proceeding?

A. All jurisdictions where consumers are subject to prices that flow from wholesale markets need to implement a rule similar to MRP 17. There also needs to be an entity responsible for implementing it. The Commission should evaluate the protections available to Arizona consumers if APS goes forward with its market-based proposals.

Q. How have higher costs been passed on to consumers in the Northeast wholesale markets?

A. One significant component of higher consumer costs is congestion costs. These costs arise due to both transmission congestion (reliability uplift) and bid-based congestion (energy uplift). In general, reliability congestion costs are socialized among all market participants. Energy congestion costs are currently allocated to specific zones in PJM and NY, and will be done in a similar manner in New England in the near future.

Q. Are congestion costs an unanticipated expense?

A. Since the markets were implemented in New England in May 1999, congestion costs have far exceeded the predictions of NEPOOL's study. This is due, in part, to the requirements of several New England states that traditional utilities divest their generation assets and serve their customers through standard offer contracts from marketplace suppliers or reliance on the wholesale spot market. One result of divestiture is that generation that had traditionally served native load is now contracted to provide power to distant customers; the delivery of that power is subject to available transmission capacity that may not be sufficient under certain seasonal load conditions. As a consequence, more expensive generation is dispatched by ISO-NE to maintain reliability, thereby incurring a "congestion" cost (the portion of the unit's bid-price that exceeds the market clearing price). These costs are then shared by all market participants based on a load allocation formula. Another reason for higher congestion costs is that bids appear to be exceeding the cost-based pricing that prevailed prior to May 1999. A study released in March 2002, which covered the start of the markets in 1999 through the summer of 2001, suggests that bids have been four to twelve percent higher than a cost-based dispatch. These higher bids are another reason that congestion occurs more frequently and at higher amounts than NEPOOL's study anticipated. Load suppliers try to deliver lower priced generation into areas with high local bids. Overall, congestion costs total hundreds of millions of dollars on an annual basis, despite ISO-NE's aggressive efforts to mitigate bids where appropriate and negotiate fixed-price contracts for reliability-must-run generation.

Q. How are congestion costs relevant to this proceeding?

A. The Arizona utilities, as recommended in other testimony, need to conduct studies to evaluate the potential constraints on their systems that could lead to congestion costs or the potential to exercise market power. As a conservative measure, the Commission should independently review these studies. Several of ENRON's

California strategies, as reported in the press, appear to have used congestion as a mechanism for raising prices.

Q. **How has MRP 17 changed over the years in New England?**

A. There have been numerous changes to MRP 17 since the implementation of bid-based wholesale markets in May of 1999. Most importantly, MRP 17 has been revised in ways that reflect FERC's efforts to balance market participants' needs for predictability and price certainty with the responsibility of ISOs to administer competitive and efficient markets. In July 2000, FERC ordered ISO-NE to revise its bid-mitigation procedures to eliminate the "excessive discretion" it had to decide when to mitigate bids. Pursuant to that FERC Order, ISO-NE adopted bid-mitigation thresholds similar to those implemented by NYISO: bids that exceed reference prices by 300% or $100 per MWH (whichever is lower) and raise the market clearing price by 200% or $100 per MWH (whichever is lower) are automatically lowered to the reference price. Recently this spring, ISO-NE has been revising its procedures for establishing prices for reliability-must-run generation. Instead of the current process of negotiating a price with each generation owner, which has been criticized as inconsistent and unfair, ISO-NE is trying to establish a formula that generation owners can select as a bid ceiling; if their bids do not exceed the ceiling threshold, they will not be reviewed for bid mitigation. Generation owners will still have the option of negotiating a long-term contract price with ISO-NE as an alternative.

Q. **What is your assessment of these changes?**

A. Although there is some value in providing clear boundaries and expectations for participant behavior, particularly bidding, the rules need to be carefully drafted to not provide "safe zones" within which participants can engage in abusive behavior without concerns about monitoring and accountability. I have some concerns that the thresholds that FERC considers appropriate are far too high, and can serve to sanction manipulative behavior. A popular comment about markets, in general, is that they work best when market participants struggle with equal emotions of greed and fear. Greed to encourage them to bid into the market in order to maximize earnings and fear that other bidders may force them out of the market with a lower bid. Until competitive pressures in the wholesale electricity markets (abundant supplies and load response) can provide the appropriate amount of fear, market monitoring needs to provide an alternative "fear", a fear that abusive behaviors will be detected and corrected.

Q. Are there other market rules that relate to market monitoring activities?

A. Yes. In New England MRP 15 provides ISO-NE with the authority to revise market prices under certain specific conditions. The NYISO has a similar authority in its rules and procedures. At the start of the markets, both ISOs had the authority to revise market prices after the fact due to market design flaws or prices that were inconsistent with a workably competitive market. This authority was utilized frequently during the first three months of market operation in NY and New England due to numerous market design flaws that were discovered after market operations began. These flaws produced prices during certain hours that were hundreds of dollars higher (per MWH) than competitive prices. FERC granted ISO-NE a sixty-day extension of this authority in August 1999, but refused a similar request at the end of September. NYISO's authority was temporary as well. FERC stated that market participants needed to have some certainty regarding posted hourly clearing prices and stated FERC's preference for *prospective* changes to market rules, rather than *retroactive* price corrections, to address market design flaws. Nonetheless, FERC left intact both ISOs' authority to correct prices for errors, such as improper data entry or miscalculations, provided that the prices were flagged for correction within a narrow timeframe of 24 hours to three days.

Q. Why are MRP 15 and similar authority important to this proceeding?

A. It is another factor that needs to be considered in terms of balancing protections and risks. A wholesale market place that seeks bid-based authority from FERC should have such a rule in place.

Q. In light of its experience with wholesale electricity markets, is the FERC considering comprehensive policy changes in regard to market monitoring and mitigation?

A. Yes, in March 2002, FERC released a Staff Working Paper on Standard Market Design ("SMD") that includes specific comments on Market Power Monitoring and Mitigation.[2] FERC has invited comments on the Working Paper and stated its intention to issue a Notice of Proposed Rulemaking on SMD this summer. The Working Paper makes some general comments as well as some detailed recommendations that reflect FERC's experience with bid-based wholesale markets. The results of this FERC proceeding will need to be reflected in the RTO filings currently pending.

FERC observes that structural solutions are more effective than behavioral solutions for mitigating market power. FERC notes that many problems in the early years were due to market design flaws and that the first priority should be to establish efficient market designs. FERC believes that SMD will help limit the problems that occur at the start of market implementation. In addition, FERC wants to see regional transmission organizations ("RTOs"), a large number of suppliers, and effective demand response programs in place as safeguards:

> RTOs and independent transmission operators are structural mitigation for vertical market power because they remove the control of transmission access from transmission companies that also compete in generation markets. With respect to generation market power, market forces such as supply and demand responses are the most potent and lasting means of mitigating market power, so solutions that increase the potential number of suppliers or increase price-responsive demand must be promoted. If market power is not mitigated through structural solutions, market rules need to be designed to mitigate market power.[3]

FERC identifies several principles that should guide the development of market power mitigation rules and a market monitoring plan. These include bid caps as a

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[2] FERC Working Paper on Standardized Transmission Service and Wholesale Electric Market Design, 3-13-02. Attached as Exhibit PRP-3.

[3] Id., at 21.

proxy for demand response, mitigation of reliability-must-run generation, assessing the overall efficiency of the market, and a preference for ex-ante mitigation instead of ex-post price changes. FERC then discusses the general structure of the market monitoring unit ("MMU"), stating that it must be independent of RTO management and report directly to the RTO Board of Directors and to FERC. In addition, the MMU should monitor all markets and conduct periodic reviews and analyses of the markets. While acknowledging that MMUs will be the first line of defense, FERC states that, ultimately, it has the responsibility for monitoring and to take corrective actions when needed.

Q. Do you concur with FERC's general principles and recommendations?

A. On many issues, I am in complete agreement. My own research confirms that market monitoring should become a more intensive endeavor in the near term; this is not a time to assume that markets will be self-correcting. An MMU needs to have an adequate budget, access to all market information, and the independence to make recommendations to both the RTO Board and the FERC. In the near-term, bid caps and other special rules (such as requirements to bid all capacity into the market every day) will provide safeguards against some forms of blatant manipulation. The RTO's authority to manage the daily power flows over the grid and through the market system will also provide significant protection against market power abuses. In a report I co-authored, commissioned by the consumer advocate offices of the Mid-Atlantic states (part of the PJM ISO service area), we chronicled in detail the market monitoring practices of the three northeast ISOs (PJM, NYISO, and ISO-NE).[4] We developed a list of 14 recommendations in that report, many of them similar to and consistent with the recommendations in FERC's Working Paper.

Q. Are you in disagreement with any of the FERC comments?

A. Not so much disagreement as a matter of different emphasis. I think FERC underestimates the need for the RTO market monitoring staff to make near-real-

[4] *Best Practices in Market Monitoring*, Peterson, Biewald, Wallach, Johnston, and Gonin, November 2001. Attached as Exhibit PRP-4.

time decisions in response to the behavior of market participants. FERC almost naively assumes that the market monitoring plan will cover all possible contingencies and that the MMU staff will just need to implement the plan. My experience at ISO-NE indicates that there are many occasions when quick action is needed. I would give the MMU the authority and discretion to act immediately to implement rule changes. I also support a limited authority for the MMU staff to flag prices for evaluation and to correct prices as warranted within a few days based on possible design flaws or market manipulation.

In addition, FERC talks almost exclusively about its concerns over the exercise of market power. I do not want to get into a word game, but "market power" is too narrow and limited a concept to encompass all the areas of market participant behavior that need to be monitored. Evaluating one company's overall market share is less helpful than evaluating each company's relative market position for each hour that it bids. That is one reason why the FERC's new pivotal test is an improvement over the traditional "hub and spoke" or HHI analyses. I prefer to think of monitoring for market abuses and manipulation, of which market power is certainly a primary concern and example. But on a day-to-day basis, there are many "behaviors" in which market participants engage, ranging from competitive to manipulative to abusive to corrupting. I am convinced that many market participants approach wholesale electricity market bidding and trading as a set of rules that they can "game" in an effort to improve their company's bottom line. A much discussed study by Cornell University shows how relatively unsophisticated "energy trader novices" can quickly learn how to manage and bid a portfolio of wholesale market electricity resources to maximize profits when they are given incentives to do so.[5] Recent revelations about trading practices in California illustrate the pervasiveness of these strategies; it is highly likely that strategies similar to those utilized by Enron in California are being utilized in other wholesale electricity markets.

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5 *Testing the Performance of Uniform Price and Discriminative Auctions*, Mount, Schulze, Thomas, and Zimmerman (July 16, 2001).

Q. What is the significance of proposed market design changes in California and recent actions of the California legislature?

A. As I stated earlier in this testimony, the FERC is indicating that it is going to be much more prescriptive in regard to the design of wholesale bid-based electricity markets. I expect that FERC is unlikely to approve significant changes to existing bid-based markets or grant market-based rate authority to any new entities until it completes its NOPRs on standardization. The market design proposals filed on May 1, 2002, by the California ISO would create substantial changes to the California wholesale market system. There is still a great deal of debate and discussion around the proposals by California stakeholders, due to the technical detail and the complexity of the proposed rules. There could be considerable delay before the FERC acts on the proposed changes. Anything approved by the FERC prior to the completion of its NOPR process will probably be conditioned on making a subsequent compliance filing that would conform to the NOPR results. Given recent revelations about the extensive and pervasive market manipulations that occurred under the previous bid-based wholesale market system in California, -- manipulations that appear to have escaped detection by the California market monitoring process and two separate FERC investigations -- I would be surprised if the FERC approved any major changes to the California markets in the next six to twelve months. While it is important to monitor the developments in California, I expect that the proposals currently being discussed are likely to be modified over the next year.

The California legislature has implemented a proposal to make California owners of generation resources subject to reporting requirements and oversight as a condition of participation in the California markets. These initiatives are designed to enhance reliability of power supplies and eliminate some of the opportunities for egregious market manipulation through the physical withholding of resources. The bill also creates a California Electricity Generation Facilities Standards Committee to perform the oversight function.

Q. Are you concerned that the removal of price caps for the Western Interconnection will produce adverse impacts for Arizona electric consumers?

A. First, I doubt that the FERC will fully remove the current price caps in September and allow unrestricted bidding in the Western Interconnection. There is just too much uncertainty about how the markets will react and the problems of 2000 and 2001 are all under the spotlight again due to the ENRON discovery documents. It is much more likely that FERC will propose some modifications or easing of the current restrictions. FERC needs to proceed cautiously and slowly to rebuild confidence in bid-based market structures in general, and in the West in particular, given the debacle in California. Regardless of FERC's actions (or inaction), Arizona consumers can remain relatively insulated from the adverse impacts of the wholesale markets through actions that can be taken by the Commission. Those actions would include many of the Staff recommendations, such as requiring a market power study before any transfers occur and ensuring that structures, safeguards, and mitigation measures are in place before "competition" should be implemented.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT PRP-1

Paul R. Peterson

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EMPLOYMENT

Synapse Energy Economics Inc., Cambridge, MA. Senior Associate, March 2001 - present. Provide consulting services on a variety of energy and electricity related studies.

ISO New England Inc., Holyoke, MA.

Coordinator of Regulatory Affairs, 2000 – 2001.
Coordinate regulatory activities with individual state public utility commissions, the New England Conference of Public Utilities Commissioners (NECPUC), and the Federal Energy Regulatory Commission (FERC). Assist the General Counsel on a variety of specific tasks and documents; draft letters and reports for the Chief Executive Officer.

Public Information and Government Affairs, 1998 – 1999.
Worked with all ISO-NE constituencies including NEPOOL Participants, regulatory agencies, and stakeholder groups in large-group and small-group formats. Developed and presented materials that described ISO-NE's functions, special projects (including Year 2000 rollover issues), and future evolution.

Vermont Public Service Board, Montpelier, VT. Senior Associate, March 2001 - present.

Policy Analyst, 1997 - 1998.
Monitored House and Senate legislation on electric restructuring; helped coordinate the passage of Senate Bill S.62 in 1997. Coordinated the New England Conference of Public Utilities Commissioners (NECPUC) activities regarding NEPOOL restructuring; assisted in drafting documents to create an Independent System Operator (ISO) for New England. Worked on New England task forces to develop a model rule for electric disclosure projects for consumer information and regulatory compliance.

Utilities Analyst, 1990 - 1997.
Reviewed regulated utility filings for changes in rates; judicial Hearing Officer for contested cases on a wide range of topics; wrote all decisions regarding annual utility applications for Weatherization Tax Credits. Focused on integrated resource planning and electric industry restructuring; initial Hearing Officer for the Energy Efficiency Utility docket. Chaired the Staff Energy Committee of NECPUC.

Energy Analysis, Burlington, VT. Consultant, 1990.
Energy-efficiency program design and evaluation.

UVM Extension Service, Burlington, VT.

Area Energy Agent, 1985 - 1990.
Performed tasks pursuant to an annual contract with Vermont Department of Public Service to conduct energy research, design energy efficiency programs and provide public education (see attached list of publications).

Home Energy Audit Team (H.E.A.T.), 1978 - 1985.
Home energy audits; energy surveys for commercial, municipal, and non-profit buildings; energy education and information.

The Close-Up Foundation, Washington, D.C. Program Administrator, 1975 - 1978.
Directed weekly government studies program for 200 high school students and teachers; supervised a staff of fifteen; coordinated curriculum and logistical aspects of program.

EDUCATION

Admitted to Vermont Bar, February 1992

Western New England College School Of Law, Springfield, MA.
Juris Doctor degree, cum laude, May 1990
American Jurisprudence Award: Remedies, 1989
Merit Scholarship recipient
Student Bar Association Representative

Williams College, Williamstown, MA
Bachelor of Arts degree, cum laude, June 1974
Political Science and Environmental Studies
Tyng Scholarship recipient

National Judicial College, Reno, NV
Administrative Hearings, Sept., 1994
Civil Mediation, March, 1996
Civil Mediation, July, 1997 (faculty assistant)

American Inns of Court, Northern Vermont Chapter
1995-1996, member
1996-1997, member

Continuing Legal Education, Vermont Bar Association
Americans with Disabilities Act, April 1992
Ethical Issues/Governmental Agencies, October 1992
Advance Medical Directives, May 1993
Family Law Workshop, September 1993
Negotiating Settlements, May 1994
Physician Assisted Suicide Symposium, October 1996
Electric Industry Restructuring, March 1999
Advance Medical Directives, May 1999
Tax Law for Non-Tax Law Attorneys, May 2000
International Law Update, June 2000

UVM Continuing Education, Brattleboro, VT

Small Computer Course, Spring 1983

Communications Workshops, Spring 1983 & Spring 1984

PUBLICATIONS & PROJECTS

Residential Construction Survey, Survey of Vermont new home construction for construction techniques, energy-efficient design, appliance loads, etc. 1986, 1989.

Vermont Vacation Home Energy Study, Survey of vacation home energy consumption and impact on Vermont statewide electrical demand. 1989.

Dairy Farm Energy Use, A detailed examination of electrical energy consumption on forty Vermont dairy farms to identify opportunities for improving energy-efficiency. 1987.

Mobile Home Booklet, A fresh look at energy saving opportunities for mobile homeowners. Specific problems of cold climates are addressed. 1987.

Dairy Farm Energy Project, Implemented $400,000 grant from Vermont Department of Agriculture for installation of milk-cooling equipment that also produced hot water. 1989.

Vocational Building Trades Instructors, Annual workshops on energy-efficient construction practices for the teachers of Vermont building trades students. Classroom presentations on selected topics. 1986 - 1989.

Brattleboro Community Energy Education Project, Coordinated a Central Vermont Public Service Company funded project to promote energy-efficiency awareness through community programs. 1985.

PROFESSIONAL CONFERENCES

Federal Energy Regulatory Commission Conference, Philadelphia, PA. March 2001.
National Association Of Regulatory Utility Commissioners, Washington, DC. 1998 - 2000
Advanced Integrated Resource Planning Seminar, Berkeley, CA 1995
ACEEE Summer Study, Pacific Grove, CA 1992 & 1994
1991 DOE Low-Level Radioactive Waste Conference, Atlanta, GA

Resume dated March 2001.

EXHIBIT PRP-2

17 MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

This Rule provides for monitoring and, in specifically defined circumstances, mitigating behavior that interferes with the competitiveness and efficiency of any or all of the NEPOOL Energy, AGC and Operating Reserve markets.

Section 6.4 of the Interim ISO Agreement states:

> **Market Assessment.** The ISO shall have the authority to independently assess the competitiveness and efficiency of the NEPOOL Market and shall convey its findings and recommendations to NEPOOL. The ISO may propose or adopt such new System Rules or Procedures as it may deem necessary or desirable to implement any such recommendations, subject to and in accordance with the procedures set forth in Section 6.17.

The ISO and NEPOOL are committed to ongoing consultation and cooperation to develop appropriate Market Rules. Consistent with the Interim ISO Agreement and this Rule, the ISO will work with the Federal Energy Regulatory Commission (the "Commission") and other jurisdictional agencies and with NEPOOL Participants to monitor for design flaws in the market, to monitor and evaluate any additional patterns of anomalous market behavior that may be detrimental to the efficient and workably competitive operation of the markets, and to determine whether they can be corrected by market design changes or improved mitigation standards.

This Rule also provides for reporting of information about the markets, including analysis based on the ISO's monitoring activity and reporting of mitigation activity.

This Rule is intended to protect and foster competition. In market monitoring and mitigation the ISO will, to the extent possible, avoid interfering with competitive price signals. Prices will be allowed to rise and fall to levels determined by competition.

This Rule provides administrative guidelines and procedures for identifying and modifying certain behaviors that may interfere with the competitive and efficient operation of the market. No action taken or report made by the ISO under this Rule 17 constitutes a finding that any party possesses market power or is exercising market power, nor a conclusion that any party has violated any law or government regulation.

17.1 MONITORING OBJECTIVES

The ISO is authorized to monitor any aspect of the NEPOOL markets to the full extent permitted by the Interim ISO Agreement. The following list of objectives is not exclusive, and is presented for the guidance of the ISO, NEPOOL Participants and others interested in the NEPOOL markets.

A seller with market power can profit by withholding its output either partially or temporarily and raising prices. Withholding may take one of two forms: physical withholding (such as declaring a Resource unavailable) and economic withholding (such as raising a Resource's bid so high it is effectively no longer available to the market). The ISO shall monitor the markets for indications of such withholding.

A seller with market power can also profit by raising the price of the Resource that actually sets the clearing price in a market or by raising its price or changing its unit characteristics to receive excess uplift in a market. The ISO shall monitor the markets for conduct that suggests the exercise of market power, including opportunistic price-setting, behavior, and attempts to receive excessive uplift payments.

In monitoring the market and implementing the mitigation procedures the ISO will recognize that the same behavior that might under some conditions suggest the abuse of market power is often, under other conditions, normal, beneficial and pro-competitive. In particular, restricting unit operation through redeclaration, operating parameters or bid prices in order to protect the safety of persons or equipment or ensure compliance with environmental licenses and permits is prudent behavior consistent with a competitive market. In addition, actions to efficiently utilize resources (including, but not limited to, fuel and emissions) in the highest value market, whether geographic, intertemporal, or component commodity market (e.g., natural gas market, or emission trading) are competitive activities and would not be subject to mitigation under this Rule. The ISO will work to ensure that these distinctions are clearly understood and that all monitoring and mitigation activities are implemented fairly and consistently in accordance with this Rule 17. Further, difficulties in accurately reflecting generator economics caused by lack of a day-ahead market, some unit commitment without consideration of operating reserve bids, and some real-time dispatch without consideration of operating reserve bids may result in the need to vary unit characteristic and bid price submittals to avoid uneconomic operation.

17.1.1 Monitoring for Physical Withholding

Physical withholding of a Resource may include, but is not limited to, (i) falsely declaring that a Resource has been *forced out of service or otherwise* become unavailable, (ii) submitting an unjustifiably inflexible set of operating parameters so that the Resource is not or will not be dispatched or scheduled when it would be in the economic interest, absent market power, of the withholding entity for the Resource to be dispatched or scheduled, or (iii) operating a generating unit in real-time to produce an output level that is significantly less than the ISO-NE's dispatch instruction.

In monitoring for physical withholding the ISO will consider a number of factors and perform a number of tasks, including the following:

Require the entity responsible for operating a Resource (whether or not it is the same entity that decides the bid) to certify confidentially to the ISO the reason for failure of a unit to be available (forced outage, derating, change in operating characteristics, etc.) as recorded in the operator's log.[1] This review will include review of the unit's compliance with the bidding requirement for Low Operating Limit set forth in Appendix 3A to Market Rule 3.

Compare current and historical outage data to determine changes in patterns of unit availability, recognizing the transition from a regulated to a market-based environment.

If the ISO detects possible physical withholding (or possible physical withholding combined with possible economic withholding), the ISO will use its best efforts to provide each seller with an opportunity to explain or justify its conduct as provided in

[1] The ISO's consideration of patterns of energy unavailability on limited energy Resources would not require routine certification of reasons for actual bid price and self-schedule strategy. The ISO will, however, investigate anomalous behavior as it arises.

Section 17.2.5 before the ISO takes corrective action. However, the ISO should not delay if the affected seller does not provide an explanation in a timely manner. There may be other unusual circumstances in which the ISO determines it needs to act before consulting with an affected seller.[2]

17.1.2 Monitoring for Specific Mitigation Thresholds

The ISO shall monitor for all the specific mitigation thresholds set forth in Sections 17.2.2 and 17.2.3. Monitoring for these thresholds may serve as the basis for mitigation under Section 17.2.4.

17.1.3 Other Monitoring Objectives

The ISO will conduct such additional monitoring as it deems necessary. Among other objectives, the ISO will monitor for:

- Behavior that may constitute economic withholding.
- Behavior consistent with an attempt to set the clearing price.
- Other price anomalies that appear inconsistent with competitive markets.
- Flaws in market design or software that reward a strategy of raising bids or overstating operating parameters in any market.
- Actions in one market that affect price in another market.
- Other aspects of market implementation that prevent competitive market results.

The ISO will include significant results of such monitoring in its reports under Section 17.6. Monitoring under Section 17.1.3 cannot serve as a basis for mitigation under Section 17.2, 17.3 or 17.4. If the ISO concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it can proceed under Section 17.5.

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[2] This includes, for example, situations where the ISO determines it must act immediately to assure the reliability and security of the system, or the efficiency and competitiveness of the market.

17.1.4 Thirty Day Average Monitoring

The ISO shall investigate the reasons for and market impact of any bids that exceed the following threshold:

A Resource's Out of Merit Order bid average for Energy Bids, AGC Bids or Reserve Bids exceeds the unit's corresponding Out of Merit Order Average Threshold as defined in Appendix 17-C.

17.2 GENERAL MITIGATION PROCEDURES

The ISO shall proceed to mitigation whenever one or more of a Participant's bids or declared unit characteristics (i) exceeds the thresholds described in Section 17.2.2, and (ii) exceeds the market impact thresholds described in Section 17.2.3, and (iii) is not explained by the Participant in accordance with Section 17.2.5 or by other information available to the ISO. The ISO shall notify the Designated Entity that it is subject to mitigation at or before the imposition of mitigation. The ISO also will disclose publicly (in its Monthly Reports) the fact of mitigation and the kind of action taken, but not the Participant or specific Resources involved. Mitigation under this Section 17.2 that affects unit commitment or dispatch shall be imposed only prospectively.

17.2.1 Market Rules to Prevent Physical Withholding

Market Rule 13 governs the imposition of sanctions for physical withholding. Other Market Rules may provide additional remedies for physical withholding or noncompliance with dispatch instructions. Nothing in this Rule limits the ISO's authority to act under Market Rule 13 or other Market Rules in the event of physical withholding. If the ISO determines that a mitigation remedy for physical withholding is necessary over and above the existing Market Rules, it may seek such authority in accordance with Section 17.5.

17.2.2 Mitigation Thresholds for Economic Withholding and Attempts to Affect Price or Uplift Payments

The following thresholds shall be employed by the ISO to identify economic withholding that may trigger mitigation:

17.2.2.1 Reference Price Screens

The ISO shall calculate a Reference Price separately for the Hot Startup Price, Cold Startup Price, No-load Price, each 10 MW block of the Energy Block Price, and each 10 Reg-hr AGC block price, of each Resource bidding in the NEPOOL markets. The block prices shall be determined as the average of the prices submitted for each MW or Reg-hr within the block.

(a) For (1) a block that has run for 15 hours or more (in the aggregate) during the past 30 days[3] for Energy, excluding (A) the megawatthours that would not have been dispatched but for the need to provide local area support in response to transmission constraints or to provide reactive power and (B) megawatthours priced above the Energy Clearing Price ("ECP") that were not eligible for Uplift compensation, or (2) a unit that has been designated for Operating Reserve or AGC for 15 hours or more (in the aggregate) during the past 30 days, the Reference Price for that block or unit shall be calculated using the formula in Appendix A.

(b) For (1) a block not covered by subparagraph (a) above that has run at least 15 hours during the past 90 days for Energy, excluding (A) any bid of zero or less than zero, (B) the megawatthours that would not have been dispatched but for the need to provide local area support in response to transmission constraints or to provide reactive power and (C) megawatthours priced above the Energy Clearing Price that were not eligible for Uplift compensation, or (2) a unit's No-Load Price or a unit that has been designated for Operating Reserve or AGC for at least 15 hours during the past 90 days, the Reference Price for that block or unit shall be the arithmetic average of those in-merit bids, adjusted for changes in fuel prices.

[3] Ordinarily this will be the most recent 30-day period. However, when a unit returns to service after an outage, this screen will evaluate the number of in-merit hours in the most recent 30 days when the unit was operable.

(c) For a unit that has started up for at least 15 times during the past 90 days for Energy, excluding (A) any bid of zero or less than zero, (B) days when the megawatthours that would not have been dispatched but for the need to provide local area support in response to transmission constraints or to provide reactive power and (C) days when megawatthours priced above the Energy Clearing Price that were not eligible for Uplift compensation, the Reference Price for Hot Startup Price or Cold Startup Price shall be the arithmetic average of those in-merit bids, adjusted for changes in fuel prices.

(d) For any bid not covered by subparagraphs (a), (b) or (c) above, the Reference Price shall be the first of the following measures that can be calculated:

(i) A level agreed on between the ISO and the Participant submitting the bid or bids at issue, provided such a level has been agreed on prior to the occurrence of the conduct being examined by the ISO; or

(ii) A reference level determined on the basis of an appropriate average of competitive bids of one or more similar units.

17.2.2.2 Investigation Thresholds

The ISO shall investigate the reasons for and market impact of any bids that exceed the following thresholds:

(a) Energy Block Price Bids: A 300 percent increase or an increase of $100 per MWh above the Reference Price, whichever is lower, but excluding bids under $25;

(b) Startup and No-load Price Bids: A 200 percent increase above the Reference Price.

(c) AGC Bids: A 300 percent increase or an increase of $100 per Reg-hr above the Reference Price, whichever is lower, but excluding bids under $5;

(d) Reserves Bids: A 300 percent increase or an increase of $100 per MW above the Reference Price, whichever is lower, but excluding bids under $5.

(e) Unit Characteristic Bids: An increase in a unit bid physical characteristic greater than 2 hours for any time based unit characteristic (e.g., minimum run time, minimum down time, cold start time, hot start time) or greater than six hours for any combination of such time-based unit characteristics,[4] or an increase greater than 20% in low operating limit, compared to the smallest (or shortest) historical bid value for the unit since May 1, 1999. Following the unit's first 89 operable days after the implementation of three-part bidding, the smallest historical bid value for the unit will be determined from bids during its first 89 operable days when three-part bidding is effective. If historical bid values are unavailable or inappropriate for a specific unit, the ISO will use historical bid values from like units.

(f) Short Notice External Transactions across the NYISO-NEPOOL interface or a transaction across other NEPOOL interfaces with a control area with published spot prices where the published price in the buyer's market is less than the published price in the seller's market will be evaluated as described in Appendix 17D. If the market impact of these transactions results in greater than an aggregate $100 per MWH change in the ECP over a day, and the Participant does not provide a satisfactory explanation to the ISO, the ISO may limit the quantity of Short Notice External Transactions the Participant may submit in the future.

If bids, pursuant to (a) through (e) above, exceed these thresholds, exceed the market impacts described in Section 17.2.3 and are not explained to the satisfaction of the ISO in accordance with Section 17.2.5, the ISO shall impose mitigation as set forth in Section 17.2.4.

[4] A decrease in one time-based characteristic shall not offset an increase in another time-based characteristic for purposes of this screen.

17.2.3 Hourly Market Impact and Uplift Thresholds

Before taking any mitigation action with regard to bids identified in accordance with Section 17.2.2 (a) through (e), the ISO shall investigate the reasons for the change in accordance with Section 17.2.5. If the bids in question are not explained to the satisfaction of the ISO the ISO will determine whether the bids in question would, if not mitigated, cause a material effect on market clearing prices in any NEPOOL market or uplift in excess of either of the following thresholds:

(a) An increase of 200 percent or $100 per MWh, Reg-hr, or MW, whichever is lower, in the hourly clearing price in any NEPOOL market for Energy, AGC or Operating Reserves.

(b) An increase of more than 100 percent in Net Commitment Period Compensation (NCPC) Energy Market component uplift payments to the Participant facing mitigation in a dispatch day, provided that the increase also exceeds $10/MWh, compared to the uplift payments calculated using Reference Prices as determined in Section 17.2.2.1 and the smallest historical bid characteristics for the Resource simultaneously for each hour. This calculation is as follows:

$$NCPC_e = Startupprice + \sum_t [NoLoadprice_t + (SE_t \times EBB_t) - (SE_t \times ECP_t)]$$

Where:

$NCPC_e$ = Net Commitment Period Compensation Energy Market Component

Startupprice = Bid Startup Price (or Reference Price)

NoLoad Price = Bid No-Load Price (or Reference Price)

SE = Supplied Energy (or Reference LOL)

EBB = Energy Bid Block Prices (or Reference Prices)

ECP = Energy Clearing Price

t = Operating Hour of the Unit associated with one continuous start-up/dispatch period when Energy was Supplied (or as determined by Reference Unit Characteristics)

The ISO shall determine the effect of questioned conduct on prices and uplift using the best available data and such models and methods as it deems appropriate.

If the bids would have an effect in excess of either of these thresholds, and has not been satisfactorily explained in accordance with Section 17.2.5, the ISO shall impose mitigation pursuant to Section 17.2.4.

17.2.4 Mitigation Remedy

If the ISO identifies bids in excess of the thresholds described in Section 17.2.2 that have the material impact on price or uplift described in Section 17.2.3, the ISO shall substitute a Default Bid in place of the bid submitted by the Participant, unless the Participant has demonstrated to the satisfaction of the ISO that mitigation is unnecessary, using the procedure described in Section 17.2.5. The Default Bid shall be 100% of the applicable Reference Price determined in accordance with Section 17.2.2.1, and with regard to uplift, the Resource shall receive uplift based on the smallest (or shortest) historical bid characteristics for the Resource, and with regard to uplift, the Resource shall receive uplift based on the smallest (or shortest) historical bid characteristics for the Resource.

Whenever a Resource is subjected to a Default Bid, the Participant responsible for deciding the bid may, if it chooses, submit a bid lower than the Default Bid, as long as the lower bid is otherwise consistent with the NEPOOL Market Rules.

17.2.5 Consultation With Affected Participant

If through its monitoring of thresholds set forth in this Section 17.2, conduct is identified that (i) exceeds an applicable threshold, and (ii) has a material effect, as specified above, the ISO shall contact the Designated Entity responsible for submitting the bid or bids identified to request an explanation. In requesting an explanation, the ISO will identify to the Designated Entity which thresholds have been exceeded. If the explanation, considered together with other information available to the ISO, indicates to the satisfaction of the ISO that the questioned conduct is consistent with competitive behavior, no further action will be taken. The ISO will consider all information a Designated Entity chooses to submit, but is not required to delay mitigation while waiting for information. The ISO will, in every case, consider explanations of bid behavior based on a Participant's cost of providing any market product, including any relevant opportunity costs and will recognize that bids for a limited energy Resource may need to be shaped to maximize the economic value from that Resource over time given the unique characteristics of the Resource.

17.2.6 Timing of Mitigation

Mitigation under this Section 17.2 that affects unit commitment or dispatch shall be imposed on the day a bid is received or used for commitment or dispatch purposes and before the bid is used to determine the hourly clearing price in any market. Mitigation affecting the amount of the uplift to which a unit is entitled may be undertaken in connection with settlement.

17.3 MITIGATION PROCEDURES FOR RESOURCES THAT ARE RUN OR USED OUT OF ECONOMIC MERIT ORDER DURING TRANSMISSION CONSTRAINTS

17.3.1 Defining the Constraint

For each hour in which the ISO designates or uses one or more Resources or portions of Resources for non-economic operation,[5] so that the Resources in question will neither set nor receive the NEPOOL Clearing Price ("CP"), the ISO will, as soon as possible after the hour:

(a) Identify each Resource or portion of Resource run or used out of economic merit order in the hour;

(b) Define and record the specific system requirement (*e.g.*, a particular transmission constraint) that caused the Resource or portion of a Resource to be run or used out of economic merit order in the hour; and

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[5] "Non-economic operation" and "out of economic merit order," as used in this document, refer to Resources dispatched and committed by the ISO that neither set nor receive the CP. *See, e.g.*, Section 14.8 of the Restated NEPOOL Agreement, which describes the Resources that set and receive the Energy Clearing Price. *See also* Restated NEPOOL Agreement §§ 14.9 (Operating Reserve Clearing Prices), 14.10 (AGC Clearing Price). As indicated earlier, Resources operated out of economic merit order neither set nor receive the CP. They receive their Bid Price for each megawatthour if the Bid Price is appropriately paid pursuant to market operations rules governing out-of-merit generation approved by the Markets Committee prior to the activation of the Participants Committee or the Participants Committee thereafter. *Id.*, § 14.5.

(c) Identify each alternative Resource, including supply Resources as well as any dispatchable demand, which was reasonably available to the operator in the hour and could have been used to satisfy that requirement.

In addition, the ISO will, as soon as possible after the dispatch day, determine if the 30-minute reserve requirement (OP8 TMOR + replacement reserves) for the system was met for all hours of the dispatch day. If the 30-minute reserve requirement was met for all hours in the day, then the ISO will apply the Market Power Screens prescribed in Section 17.3.2. If the reserve requirement was not met for any hour in the day, then the ISO will proceed to Section 17.3.1.1.

17.3.1.1 Pool-Wide Competition Screen

For a dispatch day when the system 30-minute reserve requirement was not met, the ISO will evaluate the energy bid supply stack used in the day-ahead Unit Commitment and determine for each bid block of each Resource dispatched and used for non-economic operation for transmission congestion for each hour:

(a) The cumulative MW of Resources or portions of Resources that were dispatched and used for non-economic transmission congestion;
(b) For the bid block being evaluated (the "Subject Bid Block") the cumulative MW of Resources or portions of Resources, lower priced than the Subject Bid Block, but priced above the ECP;
(c) For each Subject Bid Block, if the value determined in (a) exceeds the value determined in (b), the Subject Bid Block will receive its bid price under the congestion pricing rules. If the value determined in (a) is less than or equal to the value determined in (b), go to Section 17.3.2.

17.3.2 Market Power Screens

Each Resource or portion of a Resource identified in step (a) of Section 17.3.1 will be subjected by the ISO staff to two market power screens: (1) a structural screen, which estimates the amount of immediately available competition, and (2) a price screen, which compares the Resource's bid behavior to available competitively-based Reference Prices. The price screen recognizes the importance of frequency, severity and foreseeability to the issue of whether a particular Resource can exercise market power by raising its price significantly, and profitably above competitive levels.

17.3.2.1 Structural Screen

Could the ISO meet the requirement identified in step (b) of Section 17.3.1 without running the selected Resource (*i.e.,* are complete substitutes, including economically dispatchable or interruptible load, available to be used to meet the requirement)? *If so*, identify the alternatives. *If not*, go to Section 17.3.2.2.

(a) Identify the entity or entities that decide the bids for the selected Resource and each alternative identified in Section 17.3.1(a).

(b) If there are three or more independently controlled competing bidders that could satisfy the requirement specified in Section 17.3.1(b), the Resources run or used out of economic merit order in the hour will receive their bid price(s) under the congestion pricing rules.[6] If there are fewer than three competitors, go to Section 17.3.2.2.

(c) In circumstances where the ISO determines that the occurrence of a constraint is reasonably foreseeable to the affected Participants, and that the existing structural screen listed in item (c) above is not sufficient for that occurrence, the ISO may substitute the following structural screen for that occurrence: If there are five or more independently controlled competing bidders that could satisfy the requirement specified in Section 17.3.1(c) , the Resources run or used out of economic merit order in the hour will receive their bid price(s) under the congestion pricing rules. If there are fewer than five competitors, go to Section 17.3.2.2.

Whenever the ISO considers raising the structural screen threshold from three to five as provided for in the preceding paragraph, it will balance the need for mitigation with the risk that mitigation pricing might interfere with competitive market incentives for investment or other market response that would tend to relieve the constraint, including but not limited to transmission expansion. Mitigation shall not interfere with or substitute for the ISO's responsibilities under Section 15.5 of the Restated NEPOOL Agreement.

17.3.2.2 Price Screens

The price screens distinguish between Resources that regularly compete in the unconstrained NEPOOL market, such as units that regularly run in economic merit, and Resources that seldom run except under constrained conditions and therefore must recover their fixed costs while running out of economic merit in a relatively small number of hours.

(a) **Price Screen for Resources that Regularly Run in Economic Merit Order**

[6] ISO has developed procedures for counting the number of competing bidders and has posted such procedures on its website.

This screen compares a Resource's bids in constrained periods to the Resource's Reference Prices as determined in Section 17.2.2.1. The Energy Block Reference Price is the weighted average of the Resource's in-merit bids (excluding any bids of zero or less than zero) during the most recent 30 calendar days for comparable hours. "Comparable hours" means the same day type (weekday or holiday/weekend) and the same time of day (on-peak or off-peak hours). The average of comparable hours will be weighted more heavily towards the more recent hours during the 30 day period to reflect short-term changes in market conditions. The most recent quartile of hours is weighted 40%, the next most recent quartile of hours 30%, the previous quartile 20% and the most aged quartile 10%. A formula for calculating the Energy Block Reference Price is set forth in Appendix 17-A. The No-Load and Start-Up Reference Prices are those determined in Section 17.2.2.1.

The ISO will proceed as follows:

1. Identify each Resource identified in Section 17.3.1 that has run in merit in more than 15 hours (in the aggregate) during the past 30 days.[7]

2. Compare each of the three-part bid prices for each such Resource in the current (constrained) day and hour with the corresponding screen prices from Table 1.

3. If the Resource's bid price was equal to or less than the screen price, the Resource will receive its bid price. If the bid price was higher than the screen price, go to Section 17.3.3.

(b) Price Screen for Resources that Seldom Run in Economic Merit Order

There may be some Resources that lack a history of operation in economic merit order. For example, some generators were built primarily to ensure transmission system stability. Each such Resource is likely to present a unique situation. The ISO may determine that some of these Resources should be entitled to receive a very high bid price or have a special contractual arrangement to ensure their availability when needed to support system reliability and security. Normally

[7] Ordinarily this will be the most recent 30-day period. However, when a unit returns to service after an outage, this screen will evaluate the number of in-merit hours in the most recent 30 days when the unit was operable.

such arrangements will be negotiated prospectively. The price screen for Resources that seldom run in economic merit order is designed to create a powerful incentive for such generators to come forward and negotiate an appropriate contract with the ISO. The price screen itself is a default case designed to ensure that the ISO has sufficient bargaining leverage in such negotiations. Until the Resource owner and the ISO reach agreement, the default price screen will enable the Resource to be paid for running in the short term, while providing a strong incentive to negotiate an appropriate arrangement with the ISO (or another willing buyer) as the screen price for Energy Blocks rapidly and progressively drops to just 5% above the higher of the same-hour CP or applicable Reference CP in the unconstrained market. A formula for calculating the Reference CP is set forth in Appendix B.

The ISO may disclose details of these negotiated arrangements if and when appropriate to ensure competitive and efficient market operation.

For Resources that lack a history of operation in economic merit order, the default case is to compare their constrained-on Energy Block bids to a screen derived from the higher of the current hour CP or applicable Reference CP and Start-Up and No-Load bids to a screen based on the unit's respective Reference Prices.

1. Compare each of the three-part bid prices in the current (constrained) day and hour for each Resource identified in Section 17.3.1 but *not* selected in Section 17.3.2.2(a)(1) to the corresponding screen price from Table 2.

2. If the Resource's bid price was equal to or less than the screen price, the Resource will receive its bid price as provided for in the congestion pricing rules. If the bid price was higher than the screen price, go to Section 17.3.3.

17.3.3 Mitigation During Transmission Constraints

In place of its bid price, each Resource reaching this step in any hour will receive for the product supplied in that hour:

(a) The applicable screen price from Table 1 or Table 2;[8] *or*

[8] As the ISO and Participants develop experience with the mitigation Procedure, it may become appropriate to revise the screening prices, the mitigation prices, or both.

(b) A price negotiated with the ISO.[9]

The Energy Block mitigation price will never be higher than the Resource's bid for the hour nor lower than the CP in the hour, unless specifically agreed to in advance by the ISO and the owner(s) of the Resource.

17.3.4 Notice to Resources Subject to Mitigation During Transmission Constraints

As soon as reasonably possible after the ISO has determined that a Resource or portion of a Resource will be subject to mitigation, the ISO shall notify the entity responsible for submitting bids for that Resource or portion of a Resource: (1) that mitigation has been imposed; (2) the hour or hours when mitigation applied; (3) the mitigation price in each hour; and (4) all other information about the ISO's determination to impose mitigation on that Resource or portion of a Resource that can be disclosed to that bidding entity under the *NEPOOL Information Policy* if it applies.

17.4 MITIGATION PROCEDURES FOR EXTERNAL ENERGY CONTRACTS SUBMITTED IN CONNECTION WITH EXTERNAL CONTRACTS FOR INSTALLED CAPACITY

17.4.1 Automatic Mitigation

The ISO will mitigate the price of an External Energy Transaction (purchase) submitted in connection with an External Transaction (purchase) for Installed Capacity during OP4 conditions[9A] if the price of the External Energy Transaction (purchase) exceeds the Reference Price. In such event, the External Energy Transaction (purchase) will be given a dispatch price equal to the Reference Price.

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9 The ISO may enter into negotiations with a resource owner for any reasonable payment terms if the ISO reasonably expects the markets will function more reliably, competitively or efficiently as a result.

9A OP4 conditions are defined in the ISO's Emergency Motion for Clarification filed with the Commission on August 9, 2000 in Docket Nos. EL00-83-000, ER00-2811-000, ER00-2937-000 and ER00-2052-000 and in the Special Interim Market Rule Limiting Bids, Sheet Nos. 2201-2203, accepted by the Commission in ISO New England Inc., 95 FERC ¶ 61,184 (2001).

17.4.2 Reference Price

The Reference Price equals the highest price payable during (or if there is no applicable limit, the highest price actually paid to internal NEPOOL resources during the particular occurrence of) OP4 conditions.

17.4.3 Payments to Seller

Any Participant submitting an External Energy Transaction (purchase) that is mitigated pursuant to Section 17.4.1 shall be paid a price equal to the higher of the ECP and the actual marginal cost per megawatt for each hour that such External Energy Transaction is dispatched. The Participant's actual marginal cost per megawatt shall equal the costs incurred by the Participant under the contract supporting the External Energy Transaction plus transmission charges to import the energy divided by the megawatts actually dispatched for the hour.

17.4.4 Uplift

If the Participant's actual marginal cost per megawatt for any hour exceeds the ECP, the difference multiplied times the megawatts actually dispatched during the hour shall be treated as uplift and allocated to Participants with negative ANI for that hour.

17.5 NEW OR REVISED MITIGATION RULES

The ISO will actively seek to identify any additional patterns of behavior that will be detrimental to the efficient and workably competitive operation of the markets. The ISO will, in consultation with jurisdictional federal and state agencies, and NEPOOL Participants, develop any additional monitoring and mitigation procedures necessary to deter or correct harmful behavior and ensure competitive efficiency. This will occur within the framework of consultation with NEPOOL provided for in Section 6.17 of the Interim ISO Agreement, which also describes the circumstances under which the ISO may act unilaterally. In particular, the ISO may develop additional or modified mitigation measures, including the development of alternative thresholds and Default Bid measures, as needed in the future.

17.6 MARKET INFORMATION AND REPORTS

17.6.1 Data Collection and Retention

Section 7.2 of the Interim ISO Agreement provides:

> The NEPOOL Participants shall provide the ISO with any and all information within their custody or control that the ISO deems necessary to perform its obligations under this Agreement, subject to applicable confidentiality limitations contained in the *NEPOOL Information Policy*.

This would include a Participant's cost information if the ISO deems it necessary, including start up, No-Load and all other actual marginal costs, when needed for monitoring or mitigation of that Participant.

If for any reason the requested explanation or data is unavailable, the ISO will use the best information available in carrying out its responsibilities.

The ISO may use any and all information it receives in the course of administering the NEPOOL markets as appropriate in its monitoring and mitigation activities. Among the most important data to be used for monitoring and mitigation purposes are the following, which ISO staff will regularly collect and maintain, for a running five-year period, preserving its confidentiality consistent with the *NEPOOL Information Policy*:

(a) Clearing Price for each of the five hourly products[10] in each hour.

[10] Energy, Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, 30-Minute Operating Reserve, and Automatic Generation Control.

(b) Price bid for each Resource or portion of Resource (whether or not dispatched or used) for each hourly product in each hour. Self-scheduled Resources or self-scheduled portions of Resources will be recorded as bidding zero.

(c) Redeclarations of bids and self-scheduling in the Energy market.

(d) Hours each Resource runs or is used in economic merit order.

(e) Hours each Resource (or any portion of that Resource) runs or is used out of economic merit order (*i.e.*, the Resource in question will neither set nor receive the CP) and associated out-of-merit MWh (or other applicable unit of measure) of each product produced.

(f) Data needed to calculate hourly net purchases and sales of each Participant in the markets.

(g) In addition to the ownership information already collected by the ISO to operate the settlement system, Participants shall provide the ISO with verified statements for each Resource identifying the entity that *decides* the bid prices for each product for such Resource (which may be a different entity than the one submitting bids) and any other entity that was involved in the bidding process.

17.6.2 Periodic Reporting

17.6.2.1 Monthly Report

The ISO will publish a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period. The report will include:

(a) An overview of competitive conditions in the New England markets;

(b) Clearing prices for the period;

(c) A general framework for evaluating those Clearing prices (*e.g.*, system conditions, load, transmission constraints, aggregate unit availabilities);

(d) A listing of frequently occurring constraints that result in out-of-merit generation;

(e) A listing of each mitigation inquiry to a Participant under Section 17.2.5 and the outcome of the inquiry, and each mitigation remedy imposed, in as much detail as is consistent with preserving Participant Confidentiality; and

(f) Rule changes affecting competition in the New England markets.

17.6.2.2 Quarterly Report for Regulators

The ISO will publish a quarterly report that will be made available to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, as well as to NEPOOL Participants. The report will describe transmission constraints and contain an analysis of market conduct and mitigation activities. The entire quarterly report will be subject to confidentiality protection consistent with the *NEPOOL Information Policy* and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The *NEPOOL Information Policy* prevents the inappropriate dissemination of competitively sensitive data to individual NEPOOL Participants. The content of the quarterly reports will include the following items and will be updated periodically through consensus of the ISO and regulators:

(a) Market Clearing Price averages, ranges, and volatilities;
(b) Market Clearing Price comparisons with other deregulated pools;
(c) Magnitude of and changes in size of Residual Energy Market;
(d) Energy Uplift Payments;
(e) System loads and weather conditions;
(f) Resource and Transmission total and net capacities;
(g) Non-Transmission congestion mitigation actions;
(h) Transmission congestion activity and mitigation including unmitigated & mitigated uplift total, average and marginal costs by transmission area;
(i) Participant resource market shares; and
(j) Participant supply curves.

17.6.2.3 Annual Reviews

The ISO will present an annual review of the operations of the New England markets. The review will include a public forum to discuss the performance of the markets, the state of competition, and the ISO's priorities for the coming year. In addition, the ISO will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the *NEPOOL Information Policy*, to the greatest extent permitted by law. The review may include a discussion about whether the ISO should propose any refinement or change in monitoring or mitigation procedures. If any such refinement or change is needed, the ISO will present its proposal to the NEPOOL Regional Market Operations Committee without delay and, if required, to the appropriate regulatory agencies. The ISO may conduct reviews more or less frequently than annually.

17.6.3 Other ISO Communications With Government Agencies

The periodic reviews are in addition to any routine communications the ISO may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets. The ISO is not a regulatory or enforcement agency. However, it will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on the market and mitigation provided in the monthly, quarterly and annual reports the ISO shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the NEPOOL Regional Market Operations Committee, if the ISO determines that a market problem appears to be developing that will not be adequately remediable by Market Rules or mitigation measures;

(b) If the ISO receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;

(c) If the ISO reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market behavior constitutes a violation of law, report these matters to the appropriate state and federal agencies; and

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The ISO will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section 17.6.2.2 of this Rule.

17.6.4 Other Information Available from ISO on Request by Regulators

The ISO will normally make its records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). The ISO shall promptly make available all requested data and information it is permitted under the *NEPOOL Information Policy* to disclose to authorized government agencies. The ISO also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten business days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the *NEPOOL Information Policy*, the ISO shall notify each party with an interest in the confidentiality of the information. The ISO shall not disclose the information unless or until (a) the authorized government agency has served the ISO with compulsory process as described above, or (b) the interested party or parties have agreed with the requesting authorized government agency to voluntary disclosure of the data or information subject to reasonable and appropriate terms protecting its confidentiality that are satisfactory to those parties.

17.7 ADR REVIEW OF ISO MITIGATION ACTIONS

17.7.1 Actions That Can Be Reviewed

A Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any ISO mitigation imposed on a Resource as to which that Participant has bidding or operational authority. A participant must seek review within the time limits provided by Section 18.8.2 of Market Rule 18 for billing adjustment requests. Actions subject to review are:

- Imposition of a mitigation remedy.[11]
- Continuation of a mitigation remedy as to which a Participant has submitted material evidence of changed facts or circumstances.[12]

17.7.2 Factual Basis for ADR Review

ADR review will be based on facts and materials presented to the ISO by the Participant, as well as the facts and materials relied on by the ISO in making its mitigation decision. The goal of this process is not to create a separate ADR record, but to provide rapid review by an impartial third party of the basis for the ISO's decision and, if necessary, removal of the mitigation. ADR review is intended to operate only after the ISO and the Participant have made a good faith effort to discuss and resolve their differences.

At a Participant's request, the ISO will promptly provide the Participant with a written explanation of the basis for any ISO mitigation action imposed on one or more Resources for which that Participant has bidding or operational authority. Upon request the ISO will also identify and make available any backup data that has not already been supplied to the Participant. Based on the written explanation, the Participant may wish to submit additional information for the ISO's consideration. If the Participant does not elect to

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[11] A mitigation remedy is imposed, for purposes of ADR Review, as soon as the ISO notifies a Participant that its Resource will be subjected to mitigation.

[12] Thus, after a Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR Review on a showing of material evidence of changed facts or circumstances.

submit more information, or if the ISO does not remove its mitigation remedy based on any new information submitted, the Participant may submit the ISO's imposition of the mitigation remedy to ADR review. The written record for the ADR review will consist of (1) all information provided by the Participant to the ISO up to and including the date on which the Participant requests ADR review and identified by the Participant as relevant to the ISO's decision to impose mitigation, and (2) all information submitted by the ISO to the ADR Neutral that supports its prior written determination. The ISO shall provide the Participant with copies of all material submitted to the ADR Neutral.

17.7.3 Standard of Review

On the basis of the written record and the presentations of the ISO and the Participant, the ADR Neutral shall review the facts and circumstances upon which the ISO based its decision and the remedy imposed by the ISO. The ADR Neutral shall remove the ISO's mitigation only if it concludes that the ISO's application of the NEPOOL mitigation policy was clearly erroneous. In considering the reasonableness of the ISO's action, the ADR Neutral shall consider whether adequate opportunity was given to the Participant to present information, any voluntary remedies proposed by the Participant, and the need of the ISO to act quickly to preserve competitive markets.

17.7.4 Parties to ADR Review

The ADR review is confidential. The only parties to an ADR review are the ISO and the Participant or Participants with bidding or operational authority for the Resource or Resources on which the disputed mitigation is imposed. The ADR review and any record are not open to non-parties.

17.7.5 Remedies

The ADR Neutral shall either affirm or remove the mitigation remedy. The decision of the ADR Neutral shall not preclude the Participant from presenting new information or new proposals for voluntary remedies to the ISO, nor shall it prevent the ISO from imposing mitigation on the same Resource in similar circumstances based on new information or further discussions with the Participant. No financial compensation may be awarded in an ADR review.

The decision of the ADR Neutral shall be included as a permanent part of any file or record the ISO maintains concerning the mitigation.

17.7.6 Procedure

17.7.6.1 Objective

It is the intent of the ADR process that disputes be resolved as expeditiously as possible.

17.7.6.2 Confidentiality

All information disclosed in the course of ADR review shall be subject to confidentiality protections that satisfy the requirements of the *NEPOOL Information Policy*.

17.7.6.3 Selection and Compensation of Neutrals

NEPOOL and the ISO shall identify not fewer than three persons who they mutually agree would be appropriate to serve as ADR Neutral under this Section 17.7 and shall obtain the advance consent of such persons to serve as ADR Neutrals for the ADR procedure described in this Section. An appropriate retainer may be paid to such persons in return for their agreement to serve, which retainer shall be made a part of the ISO's budget. The ISO and NEPOOL may from time to time mutually select additional persons to fill vacancies or expand the roster of ADR Neutrals as needed.

When a Participant initiates an ADR process an ADR Neutral shall be selected from the roster within five business days using the following procedure:

- Except as otherwise provided for in Section 17.7.6.7 below, ADR processes shall be assigned to the ADR Neutral whose most recent ADR process handled under this Section 17.7 was longest ago.
- If the schedule of such member of the roster does not permit meeting the required schedule for the ADR process, that ADR process shall be assigned to the member whose most recent ADR process was next longest ago and so forth.

- If two or more members of the roster have not handled at least one ADR process or handled ADR processes as to which hearings were held on the same day, the ADR process shall be assigned among such members by lot.

17.7.6.4 Hearing

The ADR Neutral who is assigned to an ADR process shall receive the complete written record at the time of assignment. The ADR Neutral, in consultation with the parties, shall schedule a hearing to be held not later than 5 business days after the ADR Neutral is selected. The schedule may be altered either by consent of all parties or, if it is clearly not possible to provide a fair review within the schedule given the complexity of the record, at the direction of the ADR Neutral.

After reviewing the written record the ADR Neutral may pose questions in writing or in a conference call with representatives of both parties that he or she would like to have addressed at the hearing. All parties shall be copied on any written communications between the ADR Neutral and any other party. There shall be no telephone calls or meetings between the ADR Neutral and any party unless all parties have been given notice and an opportunity to participate.

At the hearing each party will have up to four hours to present its views regarding the written record. A party may reserve time for rebuttal. There will be no witnesses or cross examination, but a party may choose to have experts or counsel make all or a portion of its presentation. The ADR Neutral is free to question any presenter.

The hearing shall be held in Holyoke, Massachusetts, or such other location as the parties and the ADR Neutral may agree.

17.7.6.5 Decision

The ADR Neutral shall render a decision in writing stating whether the mitigation remedy is affirmed or removed within two business days of the hearing. No statement of reasons for the decision is required. Any party may request a meeting with the ADR Neutral to discuss the ADR Neutral's decision.

17.7.6.6 Costs

The costs of the ADR process (including any fees for the participation of the ADR Neutral in the specific proceeding but not including any retainer for the ADR Neutral) shall be assessed to the Participant if the mitigation remedy is affirmed and to the ISO if the remedy is removed. Costs assessed to the ISO shall be automatically included in the ISO's budget.

17.7.6.7 Related ADR Reviews

ADR reviews involving the same Resource or Resources or Participant or Participants may be determined by the same ADR Neutral and may, in appropriate cases, be consolidated.

17.7.6.8 Effect of ADR Process

The decision of the ADR Neutral is binding on the ISO and the Participant except as specifically provided in this Section 17.7.6.8. The ISO may appeal the removal of a mitigation remedy to the Commission. A Participant may appeal the imposition of a mitigation remedy to the Commission whether or not it has requested an ADR process. Except for this ADR process, a Participant may not seek removal of the mitigation, or any other remedy against the ISO, in any forum other than the Commission, and may not contest the decision of an ADR Neutral in any forum. The ISO may not contest the removal of a mitigation remedy in any forum other than the Commission.

17.8 APPEAL TO THE COMMISSION

A Participant may appeal the imposition of a mitigation remedy directly to the Commission whether or not it has requested an ADR process. Prior to making such an appeal to the Commission, a Participant may request a written explanation of the basis for ISO mitigation as provided under Section 17.7.2 whether or not a request for ADR review has been made. In responding to such an appeal the ISO may provide the Commission with all relevant information regarding its decision to impose a mitigation remedy but shall be under no obligation to request confidential treatment for information specifically identifying the Participant upon whom mitigation is imposed notwithstanding anything to the contrary contained in the *NEPOOL Information Policy*.

APPENDIX 17-A

REFERENCE PRICE

The Reference Price is the weighted average of (1) the bids for block of Energy excluding (a) any bid of zero or less than zero, and (b) bids for megawatthours that would not have been dispatched but for the need to provide local area support in response to transmission constraints or to provide reactive power, and (c) bids for megawatthours that are above the Energy Clearing Price and were not eligible for uplift compensation, or (2) the bids for Resources that were designated as providing Operating Reserves or AGC during the most recent 30 calendar days[13] for Comparable Hours. "Comparable Hours" means the same day type (weekday or holiday/weekend), and the same time of day (on-peak or off-peak hours). The average of Comparable Hours will be weighted more heavily towards the more recent hours during the 30 day period to reflect short-term changes in market conditions. The most recent quartile of hours will be weighted 40%, the next most recent quartile of hours 30%, the previous quartile 20% and the most aged quartile 10%.

Thus, the formula for calculating the Reference Price is:

$$RP_{DT,PO} = \left[\sum_{n=1}^{N}\left(BH_{DT,PO,W,n} \times WT_{W,n}\right)\right] \div \left[\sum_{n=1}^{N}\left(WT_{W,n}\right)\right]$$

Where:

(For all $BH > 0$)

RP = Reference Price
DT = Day type (2 = Weekday; Weekend/Holiday)
PO = Load Period (2 = On-Peak Hours; Off-Peak Hours)
BH = Historical Hour Bid
WT = Quartile Weights (4 = 4, 3, 2, 1)
W = Quartile (4)
n = Hour
N = Number of Comparable Hours in Previous 30 Days

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13 Ordinarily this will be the most recent 30-day period. However, when a unit returns to service after an outage, the Reference Price will be based on the number of in-merit hours in the most recent 30 days when the unit was operable.

During the first 30 calendar days following start-up of a new Resource or the implementation of three-part bidding, the Reference Price will be calculated as the simple arithmetic average of (1) the bids for block of Energy excluding (a) any bid of zero or less than zero, and (b) bids for megawatthours that would not have been dispatched but for the need to provide local area support in response to transmission constraints or to provide reactive power, and (c) bids for megawatthours that are above the Energy Clearing Price and were not eligible for uplift compensation, or (2) the bids for Resources that were designated as providing Operating Reserves or AGC during the most recent 30 calendar days[14] for Comparable Hours. Beginning with the thirty-first calendar day, the Reference Price will be calculated by the formula shown above. If there are no in-merit bids for Comparable Hours, the applicable Reference Price will be calculated using all hours of in-merit bids during the 30-day period.

[14] Ordinarily this will be the most recent 30-day period. However, when a unit returns to service after an outage, the Reference Price will be based on the number of in-merit hours in the most recent 30 days when the unit was operable.

During the first 89 operable days after the implementation of three-part bidding, and thereafter during the first 89 operable days after a new Resource begins operation, "number of hours" will be converted to percentages of the hours operated (by definition, fewer than 2160)[15] for the cumulative hours test in Tables 1 and 2 using the following conversion.

Cum. Hrs.	Cum. %
≤45	≤2.1%
>45-90	>2.1-4.2%
>90-135	>4.2-6.3%
>135-180	>6.3-8.3%
>180-225	>8.3-10.4%
>225	>10.4%

[15] Percentages are derived by dividing 2160, the number of hours in 90 days, into the number of hours in the 90-day cumulative hours column in Tables 1 and 2. For example, 45/2160=0.021=2.1%.

TABLE 1
(Price screen for Resources that regularly run in economic merit order)

This table contains a test based on the Resource's cumulative number of hours out of economic merit order in the past 90 days.[16]

For example, a Resource that has run out of economic merit order more than 225 hours (just over 10% of the time) in the past 90 days will be subject to a screen price 5% above the Reference Price. If the Reference Price, multiplied by the screening percentage, is less than the current day or hour out-of-merit bid, and the market structure screen identifies fewer than three total competitors, mitigation pricing will apply.

90-day cumulative hours out of economic merit order	Current hour Energy Block Price, No-load Price bid or Startup Price bids as percentage of respective Reference Price to Resources used out of economic merit order during transmission constraints.
≤45	150%
>45-90	125%
>90-135	120%
>135-180	115%
>180-225	110%
>225	105%

[16] Cumulative hours of operation out of economic merit is a measure of past performance and behavior, and will identify Resources that repeatedly run out-of-merit for relatively short periods of time, and therefore would not be identified by the consecutive out-of-merit hours test. Normally the 90-day period will be the most recent, except that when a unit is returning to service after an outage the 90 days will be the most recent 90 days in which that unit was operable. If a unit has operated for a total of fewer than 90 days since the Second Effective Date, the cumulative out-of-merit hours will be prorated as a percentage according to the table in Appendix A above.

TABLE 2
(Price screen for Resources that seldom run in economic merit order)

This table, like Table 1, contains a test based on the Resource's cumulative number of out-of-merit hours in the past 90 days. ***For example, a Resource that has run out of economic merit order more than 225 hours (just over 10% of the time) in the past 90 days will be subject to a screen price 5% above the higher of the current hour CP or Comparable Hours Reference CP for Energy Block Price and above the Reference Price for Startup and No-Load.*** If the screening percentage is less than the current hour out-of-merit bid, and the market structure screen identifies fewer than three total competitors, mitigation pricing will apply.

90-day cumulative hours out of economic merit order	For Energy Block Price, current hour bid as percentage of the higher of the current hour CP or Comparable Hours CP	For Startup Price and No-Load Price bids, current day or hour bid as a percentage of respective Reference Price
≤45	500%	150%
>45-90	300%	125%
>90-135	150%	120%
>135-180	125%	115%
>180-225	115%	110%
> 225	105%	105%

APPENDIX 17-B

REFERENCE CP

The Reference CP is the weighted average of the market clearing prices (excluding any price of zero or less than zero) during the most recent 30 calendar days for Comparable Hours. "Comparable Hours" means the same day type (weekday or holiday/weekend), and the same time of day (on-peak or off-peak hours). The average of Comparable Hours will be weighted more heavily towards the more recent hours during the 30 day period to reflect short-term changes in market conditions. The most recent quartile of hours will be weighted 40%, the next most recent quartile of hours 30%, the previous quartile 20% and the most aged quartile 10%.

Thus, the formula for calculating the Reference CP is:

$$RCP_{DT,PO} = \left[\sum_{n=1}^{N}\left(PH_{DT,PO,W,n} \times WT_{W,n}\right)\right] \div \left[\sum_{n=1}^{N}\left(WT_{W,n}\right)\right]$$

Where:

(For all $PH > 0$)

RCP	=	Reference CP
DT	=	Day type (2 = Weekday; Weekend/Holiday)
PO	=	Load Period (2 = On-Peak Hours; Off-Peak Hours)
PH	=	Historical Hour CP
WT	=	Quartile Weights (4 = 4, 3, 2, 1)
W	=	Quartile (4)
n	=	Hour
N	=	Number of Comparable Hours in Previous 30 Days

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APPENDIX 17-C

DEFINITION OF OUT OF MERIT ORDER THRESHOLD, AVERAGE AND REFERENCE PRICE

A unit's Out Of Merit Order ("OOMO") Average Threshold is calculated over Comparable Hours over the last 30 comparable days for which the unit was operable. For example, an OOMO Average Threshold might be calculated for hour-ending 4pm for the previous 30 on-peak days for which the unit was operable. The formula for calculating the Out Of Merit Order Average Threshold is:

OOMO Average Threshold = [AS*SS*ORP+(OD-AS)*ORP]/OD

AS = Allowed Spikes, lower of TAS and OD.

TAS = Total Allowed Spikes per 30 day period.

OD = OOMO Days, Number of OOMO bids in Comparable Hours for the most recent 30 comparable days for which the unit was operable.

ORP = OOMO Reference Price for Comparable Hours as calculated in this Appendix.

SS = Spike Size, % increase over the ORP.

A unit's OOMO Average is the arithmetic average of its actual OOMO bids over the most recent 30 comparable hours for which it was operable.

The OOMO Reference Price shall be calculated by the ISO separately for each block of 10MW for each generating unit or other Resource submitting bids in the NEPOOL markets. The OOMO Reference Price is the average of the Resource's in-merit bids (excluding any bid of zero or less than zero) during the most recent 30 Comparable Hours for which the unit was operable. "Comparable Hours" means the same market time period (on-peak or off-peak, with off-peak being nights, weekends, and holidays), and the same time of day (e.g. hour ending 4 p.m.).

The formula for calculating the Out Of Merit Order Reference Price is:

$$ORP_{DT,PO} = \left[\sum_{n=1}^{N}\left(BH_{DT,PO,n}\right)\right] \div N$$

Where:

(For all $BH > 0$)

ORP	=	OOMO Reference Price
DT	=	Day type (On-Peak, Off-Peak)
PO	=	Load Period (hour)
BH	=	Historical Hour Bid
n	=	Hour
N	=	Number of Comparable Hours

Sheet Nos. 1787 through 1800 are reserved for future use.

Sheet Nos. 1733 through 1749 are reserved for future use.

Sheet Nos. 1701 through 1732 are reserved for future use.

EXHIBIT PRP-3

Federal Energy Regulatory Commission
Working Paper on Standardized Transmission Service and Wholesale Electric Market Design

To enhance competition in wholesale electric markets and broaden the benefits and cost savings to all wholesale and retail customers, the Commission intends to reform public utilities' open access tariffs to reflect a standardized wholesale market design. The goals of this initiative are to: provide more choices and improved services to all wholesale market participants; reduce delivered wholesale electricity prices through lower transactions costs and wider trade opportunities; improve reliability through better grid operations and expedited infrastructure improvements; and to increase certainty about market rules and cost recovery for greater investor confidence to facilitate much-needed investments in this crucial economic sector. A key challenge will be to balance the need for standardization for a seamless transmission grid with streamlined operations and costs with the need to permit regional differences and market innovation.

The Commission is conducting this effort through Docket No. RM01-12-000 and plans to issue a notice of proposed rulemaking, containing a reformed open access transmission tariff, this summer. The reformed tariff will be filed by regional transmission organizations (RTOs) and other public utilities that own, operate or control interstate transmission facilities.

The Commission's Order Nos. 888 and 889 established non-discriminatory open access transmission services and stranded cost recovery rules for the transition to competitive markets. These rules established a sound foundation for competitive bulk power markets in the United States, but did not address every issue now before us. There is wide consensus today about the need to update the pro forma tariff and the basic elements of wholesale electric market design. On some issues, there is clear consensus about what needs to be done; on others, further policy decisions are needed to move forward. The Commission intends this paper to offer that policy guidance and allow the parties to move forward in a focused process that builds upon Order Nos. 888 and 889, and the institutional innovations of RTOs identified in Order No. 2000, to complete the establishment of robust, seamless competitive wholesale electric markets.

Based on dialogue with a wide array of stakeholders and state commissioners over the past few months, this paper lays out principles and policy decisions on the standard market design to guide the Commission in developing a revised transmission tariff. Most of these reflect consensus voiced by the parties in written comments and in the conferences and workshops held by the Commission with the industry between October 2001 and February 2002. These policy calls are subject to further dialogue with and comment from participants. The Commission will issue a notice of proposed rulemaking this summer and all affected parties will be able to further comment on the notice of proposed rulemaking. The Commission will consider all comments in determining the final rule.

Attached hereto is an Appendix that responds to a number of questions on market design from the Electronic Scheduling Collaborative.

A. The Need for a Single Transmission Tariff

Order Nos. 888 and 889 established the foundation needed to develop competitive bulk power markets. However, it has become clear that the Order No. 888 open access transmission tariff (OATT) contains provisions that, in practice and in conjunction with market design rules that currently exist in the electric utility industry, allow energy suppliers that also provide transmission service to favor their own generation and disadvantage other energy suppliers. For example, a vertically integrated utility determines available transmission capability and the facilities necessary to interconnect a new generator. In both cases, the transmission provider has the incentive to favor its own generation. This creates barriers for other energy providers, raises costs from inefficiency for all grid operations, and often results in higher delivered energy prices to end-use customers. The lack of regional coordination of the grid (for instance, the calculation of Available Transmission Capacity and Total Transmission Capacity on a company basis) contributes to inefficient operations by causing unnecessary transmission congestion and transaction curtailments. In addition, market design issues not addressed by the current tariff impede a seamless national transmission grid and the development of broad, fully competitive electricity markets.

At present there is no single set of rules governing transmission of electric energy. The electrons moving across the grid do not distinguish between bundled retail and other services, and behave according to the laws of physics rather than the laws of a particular jurisdiction. With more non-integrated electricity suppliers and a deeper reliance on wholesale electric markets, there are substantial competitive consequences and higher costs to all retail customers if we do not apply consistent, non-discriminatory rules to all transmission customers. To protect all customers and assure the benefits of competition for all, consistent transmission rules must be applied.

The existing tariff reveals different flaws in different regions of the country. In areas where most energy transactions occur through bilateral contracts without centralized spot markets for energy and ancillary services, more and more transactions are being curtailed under transmission loading relief (TLR) mechanisms that rely on non-price allocation methods. In these cases, congested transmission capacity is not being consistently allocated to the market participants who value transmission the most.

Market design flaws are visible in every regional electric market today under the existing tariff. These flaws are allowing operational problems such as the "socialization" or "uplift" of congestion management prices across all customers in a region, which obscures the potential for price signals to indicate where new generation, demand response or transmission is needed. In other regions, high fees are being collected for the value of generation capacity that do not clearly incent the construction of new capacity. A third type of flaw has been the sequential clearing of energy and ancillary service markets, which fails to deliver efficient prices for the service delivered. No region has been exempt from market design flaws of one type or another.

Even where market designs appear to be very similar in contiguous regions, "seams" problems have persisted. A seams problem occurs when differences in business practices, market design, reliability rules, or software platforms between regions impedes trade between the regions. When these seams problems prevent the economic exchange of energy, they increase transactions costs.

Even within a region, a poorly designed or inefficiently managed transmission system can result in significant increased costs to customers. It is useful to review the approximate costs of electric generation and transmission to see the impact that transmission can have on energy costs. Consider these approximate costs as viewed by retail customers (excluding distribution and load-serving entities'

(LSEs) operating costs, which represent about 15% or less of the average retail bill) for two regional markets, for the year 2000:[1]

	PJM		NY	
	$ Millions	% of Total Cost	$ Millions	% of Total Cost
Energy Costs	$9,822	92.2%	$7,599	88.6%
Congestion Costs	$134	1.2%	$1,209	14.1%
Line Losses	$491	4.5%	$380	4.5%
Transmission Revenue Requirement	$832	7.8%	$979	11.4%
Total Cost	$10,654	100%	$8,578	100%
Peak Load (MW)	49,417		30,200	

These markets are used because we have information readily available for them. These figures illustrate several important points. First, within the delivered retail bill, the cost of transmission alone is small compared to the cost of generation, but these costs are still large in absolute terms. Second, two elements which are substantially affected by the design and operation of the transmission system have a significant effect on energy costs, i.e., the cost of transmission congestion (which is actually the opportunity cost of having too little transmission) and the cost of line losses (the additional generation that must be produced to make up for energy lost in the delivery of electrons through the grid, averaging about 5% of total electricity produced). Third, the costs hint at the substitutability between generation and transmission – specifically, as the grid becomes constrained, energy costs rise markedly due to the redispatch of more expensive plants to work around the transmission constraints. This can be seen in the higher congestion costs in New York caused by the unavailability of the Indian Point nuclear plant in

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[1] Energy Costs for each independent system operator (ISO) are derived from Form 1 data for each of the utilities in the ISO. It is calculated as the sum of Total Power Production Costs (Form 1, page 321, line 80) of each of the utilities in the ISO. Congestion costs are from the websites of each ISO. Line losses are assumed to be 5% of Energy Costs (4.5% of Total Cost). The transmission revenue requirement for each ISO is the sum of the annual transmission revenue requirements of each utility in Attachment H to the OATT of each ISO. Total Cost is the sum of Energy Costs and the Transmission Revenue Requirement. Peak load for PJM Interconnection, L.L.C. (PJM) is from "PJM Interconnection State of the Market Report 2000." Peak load for New York Independent System Operator (NYISO) is from "Power Alert: New York's Energy's Crossroads" (March 2001).

the summer of 2000. Additions to the grid may slightly increase the transmission revenue requirement but yield large reductions in total energy cost per kWh from lower congestion costs and greater access to cheaper bulk power sources.

The table above shows the relative costs of energy and transmission within two areas that have markets designed similarly to the standard market design proposed here. In other areas, where transmission constraints are not managed with similar mechanisms, the impact of congestion on energy costs is likely far greater. Adoption of a standard market design in those areas would improve price signals and encourage more efficient expansion of the transmission grid with corresponding reductions in energy costs. Even if the energy costs reductions are small in percentage terms, there could still be large savings in absolute terms.

In Order No. 2000, the Commission recognized the need to make further changes to its regulations to address these inefficiencies and discrimination problems. However, Order No. 2000 primarily dealt with the structure and independence of the new RTOs. It did not directly address the market rules that were needed to achieve the objective of competitive electric wholesale markets.

We must act now to remedy any undue discrimination and unjust and unreasonable pricing caused by the problems highlighted above and to achieve the reliability and cost-saving benefits of competition. We must restructure electric transmission service to provide comparability for all sellers of electricity, use transmission assets more efficiently, and reduce inefficiencies by standardizing market rules. This should be done by creating a new, flexible transmission service to be offered by all transmission providers to all customers, with a new standard market design for wholesale electric markets.

To assure fairness and transparency for all participants, an entity independent of the market participants must administer the imbalance energy markets that are to be part of the standard market design proposed here. As described below, the Commission is proposing to use Locational Marginal Pricing (LMP) as the system for congestion management. Under LMP, the imbalance and transmission markets must operate together. Thus, it is more efficient to have one entity perform the two functions identified by NERC in its new Functional Model as the Balancing Authority and the Transmission Service Provider. In this document, we use the term "transmission provider" for the independent entity that would perform functions including accepting and processing requests for transmission service, administering the OASIS, scheduling transactions, and administering the imbalance markets. Thus, an RTO or independent system operator (ISO) would meet the definition of transmission provider. However, vertically-integrated public utilities who are not part of an RTO or ISO would have to contract with an independent entity to serve as the "transmission provider" to perform these functions. The question of whether an independent transmission company, i.e., one that has no affiliation with a generator or power marketer, qualifies as a transmission provider requires further consideration.

B. General Principles for Standard Market Design

The lessons learned in existing markets lead us to establish a set of principles to guide the development of standard market design:

1. The objective of standard market design for wholesale electric markets is to establish a common market framework that promotes economic efficiency and lowers delivered energy costs, maintains power system reliability, mitigates significant market power and increases the choices offered to wholesale market participants. All customers should benefit from an efficient competitive wholesale energy market, whether or not they are in states that have elected to adopt retail access.

2. Standardization of market design and business practices reduces transaction costs and reduces "seams issues" that restrict trading. In developing and implementing standard market design, the maximum benefit will be gained by standardizing as much as practicable. Deviations or changes from the standards must be consistent with or superior to standard market design. Such changes must also be compatible with neighboring systems to prevent seams issues.

3. Market rules and market operation must be fair, well defined and understandable to all market participants.

4. Imbalance markets and transmission systems must be operated by entities that are independent of the market participants they serve.

5. Energy and transmission markets must accommodate and expand customer choices. Buyers and sellers should have options which include self-supply, long-term and short-term energy and transmission acquisitions, financial hedging opportunities, and supply or demand options.

6. Market rules must be technology- and fuel-neutral. They must not unduly bias the choice between demand or supply sources nor provide competitive advantages or disadvantages to large or small demand or supply sources. Demand resources and intermittent supply resources should be able to participate fully in energy, ancillary services and capacity markets.

7. Standard market design should create price signals that reflect the time and locational value of electricity. The price signal – here, created by LMP – should encourage short-term efficiency in the provision of wholesale energy and long-term efficiency by locating generation, demand response and/or transmission at the proper locations and times. But while price signals should support efficient decisions about consumption and new investment, they are not full substitutes for a transmission planning and expansion process that identifies and causes the construction of needed transmission and generation facilities or demand response.

8. Demand response is essential in competitive markets to assure the efficient interaction of supply and demand, as a check on supplier and locational market power, and as an opportunity for

choice by wholesale and end-use customers.

9. Transmission owners will continue to have the opportunity to recover the embedded and new costs of their transmission systems. Consistent with current policy, merchant transmission capacity would be built without regulatory assurance of cost recovery.

10. Customers under existing contracts (real or implicit) should continue to receive the same level and quality of service under standard market design. However, transmission capacity not currently used and paid for by these customers must be made available to others.

11. Standard market design must not be static. It must not inhibit adaptation of the market design to regional requirements nor hinder innovation.

C. <u>The New Transmission Service</u>

Transmission providers should be required to offer a nondiscriminatory, standard transmission service, "Network Access Service," for all customers, including vertically integrated utilities. Network Access Service would combine features of both of the existing open access transmission services, the flexibility and universal access of network integration transmission service and the reassignment rights of point-to-point service. This allows all customers to have a system of tradable transmission property rights that will expand their transmission options and enable and enhance competition in wholesale electric markets. All transmission services should be performed under a single set of market rules.

To complement Network Access Service and implement the standard market design, transmission providers should manage congestion using LMP. To handle imbalances and the procurement of ancillary services, the transmission provider would operate markets for energy, regulation and operating reserves in conjunction with the markets for transmission services. These markets would be bid-based markets operated in two time frames: (1) a day ahead of real-time operations, and (2) in real time. For both the day-ahead and real-time time frames, the transmission provider would assure that purchases and sales of energy, regulation and operating reserves through the centralized energy, regulation and operating reserves markets, or through self-supply or bilateral contract, are coordinated with transmission services on the grid. The transmission provider would establish schedules for transmission service, and sales and purchases of energy, regulation and operating reserves, to ensure the most efficient use of the transmission grid.

<u>Network Access Service</u>

Network Access Service would give the customer the right to transmit power between two points, a source and a sink. A source is defined here as the location where a transaction originates, and a sink is defined as the location where a transaction terminates. Sources and sinks would be defined to include both individual nodes as well as aggregated points such as trading hubs. Thus, a Network

Access Service customer could use this service to move power from a generator (source) to a load (sink), from a generator (source) to a trading hub (sink), from one trading hub to another, or from a trading hub (source) to a load (sink). A Network Access Service customer would have access to all sources and sinks on the system. An access charge would be used to recover the embedded costs of the transmission system. The manner in which embedded costs will be recovered requires further discussion to be resolved.

Some transactions cannot occur without causing congestion on the transmission system. Network Access Service gives customers two options for how to handle the costs of this congestion, either: (1) a predetermined price, using "transmission rights," or (2) the applicable congestion charge in which the customer bears the full cost of congestion management. The issue of how to allocate transmission rights is difficult and contentious. However, our intent is to preserve the existing rights of current users of the system.

Transmission rights for transmission price certainty

A customer can achieve price certainty for Network Access Service by acquiring transmission rights. A transmission right allows the customer to schedule power from specific source(s) and sink(s) without having to pay congestion for service between those points. Anyone can hold a transmission right. A key implementation issue will be the initial assignment of transmission rights. One option is to directly allocate the transmission rights to customers that pay the embedded costs of the system. Any transmission rights not claimed by these customers would be auctioned. Another option would be to conduct an auction to apportion the transmission rights, with the proceeds from the auction allocated to those customers that pay the embedded costs of the system.

However transmission rights are initially issued, transmission rights holders can sell them into a secondary market so that others can buy transmission price certainty. If a transmission rights holder chooses not to schedule transmission service at a particular time, the transmission capacity will be made available to the market and the transmission rights holder will receive the associated congestion revenue.

The transmission provider must offer to sell transmission rights for all of the capacity on the grid, but it cannot sell more rights than the capacity can accommodate. After the initial allocation of transmission rights, there may need to be a regular reallocation of the transmission rights or the auction revenues to reflect changes in load responsibilities due to retail unbundling or other factors. Over the long term, if a customer (or merchant transmission company) pays to construct new transmission facilities that add transfer capability, the entity that pays for the construction, whether a customer or transmission owner, should receive the transmission rights associated with the new transfer capability (unless they receive credits against the Network Access Service access charge). This issue needs further consideration.

Transmission without price certainty

The alternative to predetermined transmission prices under transmission rights is for the Network Access Service customer to schedule service by agreeing to pay for any congestion costs of a particular transaction. Congestion costs occur when the capacity of the grid is limited and it is not possible to transfer more energy across the grid from the customer's intended source to sink without compromising grid reliability. In this situation, the transmission provider will redispatch a more expensive generator on the other side of the constraint to deliver to the intended sink. The incremental cost of this "out-of-merit" redispatch is charged to customers who have not secured transmission rights. Customers who hold transmission rights would not be charged the redispatch costs.

Day-ahead scheduling

Every day, the transmission operator would develop a schedule for use of the transmission system for each hour of the next day. The schedule would accommodate the requests of customers with transmission rights and those without, as well as transmission needed for delivery of purchases and sales made through the centralized energy spot market (described further below). Customers with transmission rights who want transmission service between their designated source and sink points would schedule their desired service between those specific points, and would be charged for losses but not congestion. Customers without transmission rights (including the transmission provider on behalf of customers purchasing or selling through the centralized energy spot market) would also schedule transmission service, by agreeing to pay the costs of losses and congestion between the desired source and sink points. Transmission rights are either source-and-sink-specific or flowgate-specific (discussed below). If a customer with transmission rights for a specific source-sink pair (from A to B) wants transmission service between a different set of source and sink points (from C to B), the customer would need to pay the cost of congestion and losses for transmission service between those new points (C to B).

Through the scheduling process, customers will be able to react to price signals by indicating how prices affect their demand for transmission service. In requesting transmission service, customers without transmission rights could either: (1) submit a bid stating the maximum congestion charge they are willing to pay for transmission service, or (2) indicate that they desire transmission service regardless of the price. Customers with transmission rights could voluntarily submit bids indicating the price above which they are willing to reduce their purchases of transmission service in exchange for receiving congestion revenues. For example, a customer with transmission rights from A to B may prefer receiving the congestion revenues if the congestion costs between those points is over $150 per MWh. In that case, the customer would voluntarily reduce its demand (for example, through a demand-side response program) for transmission service between those points.

If there is sufficient transmission capacity to accommodate all requested transmission service, then all requests would be scheduled, and all scheduled customers would pay a charge to recover the applicable cost of losses. However, if the amount of transmission service desired along one or more transmission paths exceeds the transmission capacity (thereby resulting in transmission congestion), then the charge for using each congested path would be raised sufficiently (based on the cost of redispatch and the price bids for transmission service) to alleviate the congestion by reducing the demand for transmission service. The added charge would be paid only by customers without transmission rights along the desired transmission path (or flowgate). As noted above, a transmission rights holder would receive congestion revenues when the path (or flowgate) is congested and the transmission rights holder elects not to schedule all or a portion of its rights.

Real-time transactions

Once all day-ahead transactions have been scheduled, any remaining transmission capacity will be made available for real-time transactions. Transactions that were not scheduled a day ahead would flow at a charge that covers the applicable cost of losses and any congestion associated with necessary redispatch. A customer with transmission rights between a specific source and sink that did not schedule transmission service between those points a day ahead could still obtain transmission service in real time. In that case the customer would pay the real-time congestion costs and losses. The customer would also receive the congestion revenues from the day-ahead market for those points.

Additional features of the standard transmission service

Transmission prices (to recover congestion and losses) developed in the transmission market must be consistent with locational energy prices developed in the energy market. A locational energy price equals the delivered cost of electricity to that point, which equals the sum of the energy price plus its congestion cost plus the value of transmission line losses from the source to the sink. The difference in energy prices between two locations should equal the transmission price that will be paid by customers without transmission rights to transmit power between these two points.

Transmission rights can be defined in two ways: (1) source-to-sink rights, and (2) flow-based, or flowgate, rights. Both source-to-sink and flowgate rights are direction-specific (i.e., a right in one direction is different from a right in the opposite direction). A source-to-sink right is specified by a source (which can be a generator node, an aggregation of generator nodes, an interface, or a trading hub) and a sink (which can be a delivery node, an aggregation of delivery nodes, an interface, or a trading hub), and the total MW that are to be injected and withdrawn from the system at a point in time. It entitles the holder to schedule transmission of the specified MW of energy in the day-ahead market from the source to the sink without paying congestion charges. To the extent that the holder does not schedule its full MW entitlement, the holder is entitled to collect the congestion revenues from the source to the sink for the unscheduled capacity.

A flowgate right is specified by the total MW capacity over a particular transmission facility (or group of facilities, e.g., an interface) rather than just the source and sink points. It entitles the holder to receive the congestion revenue associated with the specified MW flow over the identified transmission facility in the specified direction.[2]

Transmission rights can be specified as obligations or options. An obligation requires the customer either to (a) physically transmit energy from its source to its sink points, or (b) receive the congestion revenues (either positive or negative) between the points. An option gives the customer the entitlement to transmit energy or collect the congestion revenues, but the customer has no obligation to do either.[3] Currently, the transmission rights offered in ISOs that use LMP are obligations, although there is customer interest for transmission rights that are options. Existing firm point-to-point transmission contracts are similar to transmission rights that are options. At the start of Network Access Service, the transmission provider must offer source-to-sink obligations. Upon the request of market participants, the transmission provider must also offer source-to-sink options and flowgate rights as soon as it is technically feasible.

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[2]Consider, for example, a very simplified transmission network that connects two points, A and B, with two different but interconnected transmission lines, a northern line and a southern line, as shown below:

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          North Flowgate
A  o--------------------------------------o
   |                                      |
   o--------------------------------------o  B
          South Flowgate
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Each transmission line would be a separate transmission facility or flowgate, and separate flowgate rights could be issued for each line. The holder of a flowgate right on the northern line from west to east would be entitled to the congestion revenues associated with that line in the west-to-east direction. However, holding a flowgate right on the northern line would not entitle the holder to congestion revenues associated with the southern line. Hence, if transmission service results in energy flows over several flowgates, the buyer must obtain sufficient rights on each flowgate to obtain a complete congestion hedge. By contrast, the holder of a source-to-sink right from west-to-east (i.e., from A to B) would be entitled to congestion revenues in the west-to-east direction regardless of whether the northern or the southern lines were congested and thus would have a complete hedge for this transaction.

[3]The difference between obligations and options becomes important when congestion occurs in the opposite direction from the right, that is, when there is congestion from the sink to the source points. In this case, congestion revenues in the direction of the right are negative. "Collecting" negative revenues means the holder pays congestion revenues to the transmission provider. If the rights holder does not physically transmit from its source to its sink when congestion is negative, an obligation holder must pay congestion revenues, but an option holder would not be required to pay.

D. Energy Market Design

One of the problems under the current OATT is the treatment of imbalances. The current rules give a competitive advantage to control area operators because they allow the operator to net out its imbalances over a large load and operate a number of power plants, while charging other sellers and buyers penalties for imbalances. The remedy for these problems is a balancing market with imbalances charged the real-time price for any excess or deficiency of energy.

Unlike gas pipeline systems, electric systems must balance supply and demand in real time. In electric networks, this balance is generally achieved by adjusting generator settings (energy production) rather than controls on the electric transmission network itself (as is done for the gas transmission system). Additionally, electric systems are affected by the operation of other electric systems in the interconnection (i.e., loop flow and parallel flows as externalities affecting all transactions on the grid), while gas pipelines rely on controls on the gas transmission network to balance supply and demand and do not face significant interaction and interdependency effects.

These differences in the operations of the systems argue for different systems for handling imbalances. On a gas system with storage, a small daily imbalance may have little or no operational effect and not threaten service to other customers. But on an electric transmission system, a similar imbalance could threaten service reliability unless the imbalance can be cured in real time. Consequently, while there is no need for centralized regional coordination on a gas system, such a need exists for an electric system, and that coordination is best effected using a real-time market for energy. Such a real-time market will improve system efficiency and lower costs relative to the requirements of Order Nos. 888 and 889.

While a day-ahead market is not strictly necessary for resolving imbalances, experience has shown that the combination of a day-ahead market and real-time market enhances system reliability and efficiency compared to operating only a real-time market. The day-ahead market lets the system operator ensure that sufficient generating units and transmission elements are committed to serve the next day's load. The day-ahead market also provides the opportunity for a generator's bids to better reflect the operational constraints and costs of generating units through multi-part bidding. Additionally, the day-ahead market provides better scheduling opportunities for the demand side to participate in the market. Markets that have operated with both a real-time and day-ahead market are more efficient than those with only a real-time market.

Day-Ahead Energy Market

The transmission provider must operate a day-ahead market in order to develop a joint day-ahead schedule for transmission service, energy, and ancillary services. The day-ahead schedule will be developed so as to maximize the combined economic value of transmission service, energy, and ancillary services, based on the bids submitted.

The energy market component of the day-ahead market performs two functions – through bids evaluated at auction, the market selects those units to be run in the next day and sets the energy prices to be paid in each hour for that energy. Those unit commitments are coordinated with the transmission scheduling operation to assure that energy can be delivered from the generation point to the delivery point, in a secure and reliable fashion.

General Features

1. The transmission provider must run a voluntary, bid-based, security constrained day-ahead market. "Voluntary" means that market participants do not have to buy or sell in the day-ahead market, as explained further below. "Bid-based" means that participants in the energy market may provide prices over the range of quantities that they offer into the market or seek to buy from the market. "Security constrained" means that the market administrator, through the energy auction process, accounts for all transmission system constraints, such as contingency limits, needed for reliable system operations.

2. The day-ahead market should be transparent (i.e., the rules of operation should be clear and understandable, and the software implementing the rules should produce predictable results) so that market participants can offer informed bids and trust market operations.

3. Since the day-ahead market is voluntary for market participants, market participants should be able to schedule bilateral transactions and/or self supply rather than bid into the day-ahead market. Long-term contracts and other means of avoiding price volatility and ensuring generation capacity adequacy should be fully accommodated.

4. Bidding parameters must allow customers the opportunity to reflect the value they place on purchasing in the energy market and allow suppliers the opportunity to reflect the costs and operational constraints of production in the energy market.

5. Demand can best respond by participating in the day-ahead market. Demand response options should be available so that end users can respond to price signals and reduce loads as they feel the price exceeds their individual willingness to pay for delivered electricity.

Scheduling and Bidding Rules

6. The demand side must be able to participate in the energy market. The demand side can participate as buyers or sellers (e.g., offering to sell operating reserves). As a buyer, an entity must be able to submit bids that indicate it is willing to vary the quantities it purchases based on the prices that it may be charged.

7. Sellers (including demand side) must have the option of submitting multi-part bids, e.g., submitting separate but related bids for start-up costs, no load costs and energy. Multi-part bidding allows generators to provide more detailed cost information that can improve the ability of the grid operator to dispatch generators with the lower total cost. Buyers must also be able to submit multi-part bids that indicate the time and price constraints under which they are willing to purchase energy in the day-ahead market.

8. Individual market participants must not be required to submit balanced schedules (where demand and supply are equal), although they may submit balanced schedules if they choose to. The transmission provider will match separate unbalanced supply and demand bids to ensure that aggregate generation and load are matched and the aggregate schedule is balanced. However, as discussed in principle 11 in the Real-Time Energy Markets section below, special rules may be necessary to address deviations in real time from day-ahead schedules that threaten transmission reliability.

9. Bids need not be tied to a physical resource. However, for reliability purposes, bids must indicate whether or not they are tied to a physical resource.

10. Limits may be necessary on bidding flexibility to mitigate market power. For example, suppliers may be required to submit a start-up bid which would remain in place for a period of several months (rather than re-bid every day). As more demand response becomes available in a regional market, limits on supplier bidding flexibility can be relaxed.

11. Additional scheduling options may need to be developed to address the special conditions facing energy-limited resources (e.g., hydroelectric power and environmentally constrained thermal power). However, these additional options should be available to all generators and should not be restricted to energy-limited resources, unless such restrictions are necessary to mitigate market power that has arisen.

12. Intermittent resources should be able to participate in the day-ahead market on the same basis as other resources.

Price Determination and Settlement

13. Nodal pricing must be used for both buyers and sellers in the day-ahead market. Nodal pricing establishes separate prices at each node (in contrast to zonal pricing, which establishes the same price at all nodes within a zone regardless of congestion). Energy prices incorporate the total value of generation, transmission congestion, and losses at each node on the system.

14. An auction must be run to establish a single market-clearing price at each node. These prices at a minimum are hourly prices. (Smaller time intervals are acceptable.) Buyers and sellers transact at the clearing price. However, if a seller's total bid costs (including startup, no-load costs, minimum run time, and other physical characteristics as well as energy running costs) over the entire day are not fully covered by its revenues from selling at the hourly clearing prices, it will receive an uplift payment for the net revenue shortfall for the day. Hourly energy prices are based only on energy bids; start-up cost bids are not used in calculating hourly energy prices. Thus, a generator may have legitimate start-up costs that are not fully covered by selling at the hourly energy price over the day; paying uplift may be necessary to ensure that generators selected in the auction will receive revenues that fully cover their bid-costs.[4]

15. The results of the day-ahead market must be financially binding on buyers and sellers. In other words, sellers must be paid the day-ahead price for energy scheduled to be sold in the day-ahead market, and buyers must pay the day-ahead price for energy scheduled to be bought in the day-ahead market. In addition, to the extent sellers and buyers fail to produce or take energy according to their respective schedules, such imbalances must be settled at the real-time energy price. Thus, a seller must pay the real-time price for any scheduled energy that it promises but fails to produce in real time. Similarly, a buyer must be paid the real-time price for any scheduled energy that it promises but fails to take in real time.

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[4]For example, suppose that the transmission provider needs to supply an additional 100 MW load in each of 20 hours over the next day. Two generators, A and B, are available. Generator A has energy costs of $30/MWh, but must incur $10,000 in start-up costs before beginning production. Generator B has energy costs of $40/MWh, and has no start-up costs. Generator A's total cost of meeting the load would be $70,000 (i.e., total energy costs of $60,000 [$30/MWh x 100 MWh x 20 hrs] PLUS start-up costs of $10,000). Generator B's total cost would be $80,000, comprised exclusively of energy costs (i.e., $40/MWh x 100 MWh x 20 hrs). Generator A should be chosen because its total costs ($70,000) would be less than Generator B's total costs ($80,000). Suppose that the hourly clearing price in each hour is $32/MWh. By selling 100 MWh in each of 20 hours, Generator A would receive total revenues of $64,000 (i.e., $32/MWh x 100 MWh x 20 hrs), which is $6,000 less than its total bid-in costs of $70,000. Generator A would thus need to receive a $6,000 uplift payment in addition to its energy revenues. Paying $6,000 in uplift is still cheaper for customers than the alternative of dispatching Generator B.

16. Upon request of the market participants, the transmission provider should establish trading hub(s), i.e., a hub price that is the weighted average of prices at selected nodes on the system.

17. The transmission provider must post prices and other market information and settle the markets on a timely basis to provide market participants with reliable information regarding their market transactions.

Real-Time Energy Markets

General Features

1. The transmission provider must run a bid-based, security constrained real-time market. These characteristics are explained above.

2. The real-time market should be transparent so that market participants can offer informed bids and trust market operations.

3. Market participants must be able to revise their schedules for bilateral transactions, including long-term contracts, and self-supply after the close of the day-ahead market. However, all imbalances will be settled through the real-time market, i.e., to the extent a buyer or seller is short, it must purchase power at the applicable real-time price for the shortfall; to the extent the buyer or seller is long, it will be paid the applicable real-time price for the excess amount.

Scheduling and Bidding Rules

4. Bids to sell in the real-time market must be one-part energy bids, i.e., bids for energy only. (Separate bids should not be submitted for start-up and no load costs since the energy suppliers should already be on-line and ready to respond to dispatch instructions. Real-time market bids may, however, include information regarding minimum run times).

5. The demand side must be able to participate in the real-time market.

6. Limits may be necessary on bidding flexibility to address market power issues.

7. Additional scheduling options may need to be developed to address the special conditions facing energy-limited resources (e.g., hydroelectric power and environmentally constrained thermal power). However, these additional options should be available to all generators and should not be restricted to energy-limited resources, unless such restrictions are necessary to mitigate market power that has arisen.

8. Intermittent resources should be able to participate in the real-time market on the same basis as other resources.

Price Determination and Settlement

9. Nodal pricing must be used for both buyers and sellers in the real-time market. Locational energy prices should reflect transmission congestion and losses.

10. Real-time prices will be established for each node through market clearing price auctions. These prices are generally for five-minute periods within the hour. Buyers and sellers transact at the clearing price.

11. All deviations and imbalances from the day-ahead market will be settled through the real-time market at the real-time price. In addition, real-time imbalances (i.e., individual market participants' uninstructed deviations in real time from their day-ahead schedules or dispatch instructions) that threaten transmission system reliability may require special rules, including penalties.

12. The transmission provider must post prices and other market information and settle the markets on a timely basis to provide market participants with reliable information regarding their market transactions.

Regulation and Operating Reserves to Meet Reliability Requirements

Transmission providers must ensure that ancillary services, including regulation and operating reserves, are provided. Regulation provides moment-by-moment balancing of generation and load on the system. Operating reserves ensure reliable service by covering contingencies such as the failure of a supply source or a transmission line. Order No. 888 envisioned that these would be provided as a tariff service subject to a cost-based rate. With the establishment of markets to provide balancing services, a more market-oriented approach is needed for regulation and operating reserves. (Other ancillary services, such as reactive power, would continue to be procured much as they are today.) The same generators that could be supplying regulation or operating reserves also could be supplying energy for balancing services. Procuring regulation and operating reserves compatibly with the procurement of energy for balancing services will lead to a more efficient and rational price structure for both. As noted below, the technical requirements of regulation service are different from those of operating reserves, so it is likely that some differences in their respective market rules will be appropriate.

General Features

1. The LSE has the responsibility to procure regulation and operating reserves or pay for the regulation and operating reserves procured by the transmission provider on its behalf.

2. Suppliers of regulation and operating reserves must meet specific operational requirements to provide these services. For example, generators offering regulation typically must have equipment providing automatic generation control capability. Suppliers of these services also typically must meet response time requirements; regulation needs to fully respond to a dispatch instruction within 5 minutes, while various categories of operating reserves must respond within 10 minutes or longer. Demand must have the opportunity to supply operating reserves if it meets the necessary operational requirements (which should be designed to enable demand response participation).

3. The transmission provider must have a bid-based day-ahead and real-time market so it can procure regulation and operating reserves on behalf of LSEs. If there are a limited number of sellers for certain operating reserves, then market power mitigation measures may need to be included in the market design.

4. Reliability authorities may establish locational requirements for operating reserves. To the extent they choose to do so, this may require the reservation of transmission capacity. The cost of the "transmission reserves" must be included in the total cost of procuring the operating reserves for the LSE involved.

<u>Scheduling and Bidding Rules</u>

5. LSEs that have a regulation and operating reserve obligation may fulfill this obligation through self-supply, bilateral transactions, or by paying the market-clearing price in the auction run by the transmission provider. LSEs may meet their obligation through combinations of these transactions as long as the full obligation is met.

6. The transmission provider must procure regulation and operating reserves through a bid-based auction for all those who do not self-supply. The financial responsibility for regulation and operating reserves procured through the auction will be borne by those LSEs that did not self-supply.

7. Demand-side supply of operating reserves must have non-discriminatory bidding opportunities in the market.

8. Regulation and operating reserve markets must allow sellers to submit availability bids in addition to energy bids. The availability bid allows the bidder to specify the minimum payment that it requires to be available to provide regulation and operating reserves.

Price Determination and Settlement

9. The day-ahead regulation and operating reserve markets must clear simultaneously with the day-ahead markets for energy and transmission service in bidding and scheduling. The market-clearing prices must be based on winning bids that jointly optimize energy, regulation, operating reserves, and transmission service.

10. Market rules should be structured so that the price of energy is never less than the price of operating reserves and the price of higher-quality operating reserves is never less than the price of lower-quality operating reserves. For instance, the market-clearing price of spinning reserves must never be lower than the price of non-spinning reserves. The price of non-spinning reserves with a shorter availability (e.g., ten minutes) must never be lower than the price of non-spinning reserves with a longer availability (e.g., thirty or sixty minutes).

11. All market-clearing prices must recognize the substitution possibilities among operating reserves and conduct a least-cost procurement of the products. Higher-quality operating reserves bid at lower cost must displace lower-quality operating reserves at higher cost.

E. Other Changes to Improve the Efficiency of the Markets under Standard Market Design

The changes discussed above will require extensive revisions to the current pro forma tariff. The OATT also establishes other rules on the provision of transmission service. Some of these rules also need to be updated to achieve the objective of a competitive wholesale electric market. There are inefficiencies in the application of some of these rules on a company-by-company basis rather than on a regional basis. In others, the OATT does not allocate the costs of reserved capacity to only those customers that have reserved the capacity. The remedy is to update the OATT to correct these problems.

1. Capacity Benefit Margin (CBM), which is a set-aside of transmission capacity by the transmission provider to ensure access to external resources in case of a contingency, ties up valuable interface capacity without a specific reservation and payment by the customers who benefit from the service. Therefore, capacity currently set aside for CBM should not automatically receive a transmission rights allocation, but should be posted on the OASIS and specifically reserved and paid for by the entity requiring the service, whether it be for additional reliability or access to other resources.

2. Calculations of transmission capability and the performance of facilities studies for transmission expansions should be performed by an independent entity. This reduces the ability of an entity to use its transmission system to favor its own generation.

3. The new tariff should recognize the regional nature of today's energy markets. As such, transmission capabilities must be calculated not for one utility's service territory, but regionally to encompass existing trading patterns and power flows, particularly parallel path flows on neighboring systems. All transmission providers that are not part of a Commission-approved RTO must contract with an independent entity to perform transmission capability calculations on a regional basis. Likewise, a common OASIS should be required for the region.

4. Proactive long-term planning and expansion must be done regionally. The RTO, must offer a mechanism for participants to bring long-term planning and expansion needs and proposed solutions to the RTO. The RTO would choose an ultimate solution, whether transmission, generation or demand side, after vetting proposals through an open stakeholder process. The recommended solution(s) must then be put out under request(s) for proposals for construction and/or implementation. If a transmission provider is not part of an RTO, it must participate in regional long-term planning and expansion.

5. To minimize the implementation costs of standard market design, the software should be modular to allow multiple vendors to provide the components of the overall software platform. Standardized data formats and data transfer protocols may also be appropriate to minimize implementation costs.

F. Market Power Monitoring and Mitigation

Market rules, such as poor auction designs, can create or enhance market power by artificially limiting entry, preventing demand response, or providing artificial incentives to withhold. Many of the problems with generation markets identified by market monitors in the first few years of regional market operations have been caused by design flaws. The standard market design will include preventive mitigation measures in the form of bidding rules. The best way to avoid market power stemming from poorly designed markets is to establish efficient designs. Market rules should mitigate market power in the least intrusive manner.

Structural solutions to mitigate market power are generally more effective than behavioral mitigation. RTOs and independent transmission operators are structural mitigation for vertical market power because they remove the control of transmission access from transmission companies that also compete in generation markets. With respect to generation market power, market forces such as supply and demand responses are the most potent and lasting means of mitigating market power, so solutions that increase the potential number of suppliers or increase price-responsive demand must be promoted. If market power is not mitigated through structural solutions, market rules need to be designed to mitigate market power. For example, locational market power in generation load pockets with only one or a small number of generating units will require behavioral mitigation. These load pockets should be identified and the behavioral mitigation measures should be in place before implementation of standard market design.

Market monitoring should focus on two general areas. First, it should identify any problems in the design of the market that lead to inefficient outcomes and should propose prospective market rule changes. Market monitoring should serve as an early warning system for events that are not yet severe, so corrective action can be taken before exercises of market power become significant and sustained. Second, market monitoring should focus on the behavior of the market participants. Market power can be exercised by withholding capacity or output from the market (physical withholding) or raising the price or offer (economic withholding). Therefore, monitoring for withholding will be an important focus of market monitoring activities. Market monitoring units (MMU) within each region will be the first line of defense, but ultimately the Commission has the responsibility for monitoring wholesale energy markets and the authority to take corrective actions when needed. For transmission providers that are not part of an RTO, further thought is required to address market monitoring.

Set out below are some general principles to guide the development of market power mitigation rules and a market monitoring plan, as well as some specific measures that should be included in the standard market design. These are based on the Commission's experience with market power mitigation methods in recent years and are intended to reflect the best observed practices that are compatible with the elements of standard market design.

<u>Principles</u>

1. Market rules should be designed to improve the competitive structure of the markets and to build into the design of the markets customer protections against market power.

2. Market rules should minimize market power by facilitating new entry and increase demand response to improve the competitive structure of the market.

3. The regional transmission planning process should identify opportunities for increasing competition, particularly the elimination of local market power when possible, and should be aggressive about facilitating new demand response, transmission or generation construction as needed.

4. Where behavioral rules are needed to mitigate market power, the mitigation rules should be clear, and not subject to discretionary actions. Effective ex ante mitigation is preferable to retroactive price changes.

5. Market rules should not require offers to sell below marginal opportunity costs of a unit, including the verifiable geographic opportunity cost of selling to other regions and the temporal opportunity cost of selling energy-limited resources in other time periods.

6. Market monitoring should focus on detecting economic and physical withholding (as distinct from the normal operation of supply, demand, and true scarcity) and assessing the efficiency of the market.

Mitigation Measures

7. A bid cap, as a proxy for demand bidding, must be in effect until sufficient demand response develops in the relevant wholesale power market. Mitigation rules that limit bidding flexibility will also be needed. As a region develops substantial price-responsive demand, mitigation rules can be reduced correspondingly.

8. The transmission provider may identify generating units that must run for reliability. Because these units have locational market power, the bids submitted by these units should be subject to mitigation. Similarly, market power in load pockets must be mitigated with on-going behavioral mitigation, such as call options or bid caps, unless structural solutions are possible.

9. Limitations on the flexibility to change bids, e.g., for start-up and no load costs, may be needed. For example, it may be appropriate to limit how often market participants are permitted to change their start-up and/or no load bids.

10. The transmission provider must be able to coordinate maintenance and outage schedules for generation and transmission facilities in order to assist in reliability planning and to monitor withholding. Information on maintenance and outage schedules should be made available to the market on a timely basis.

Monitoring

11. Each RTO should have an MMU that is independent of the RTO management. The MMU should be funded by the RTO, but it should report directly to the Commission and to the independent governing board of the RTO.

12. The Commission will exercise oversight of MMU activities and the impact of RTO operations on the efficiency and effectiveness of the market.

13. An MMU will monitor all markets (including the impact of generation, transmission, and load) in its region, principally for economic and physical withholding.

14. The MMUs will conduct periodic reviews and analyses of the general performance of the markets, and the impact of the market rules, on the efficiency and effectiveness of the markets in the RTO's region and will propose rule changes, when appropriate, to the Commission.

15. The MMUs should work with each other, the states and the Commission to develop market performance measures that are common to all regions.

G. Long-Term Generation Adequacy

Most of the above discussion deals with maintaining reliable day-to-day operations of the system in a market-oriented way. On a long-term basis, for the system to be reliable and the markets to function efficiently, there must be adequate generation resources and transmission resources. To do that, there may be a need to include specific measures to ensure that LSEs maintain a reasonable supply reserve margin. The issue of how to do this is a contentious one that needs further discussion among industry participants. However, there are certain basic principles that should be used in standard market design.

1. Standard market design may include measures to ensure adequate long-term generation supplies. Any such measures should be forward-looking and flexible enough to accommodate changing load obligations.

2. Preferably, state and regional reliability authorities will coordinate with one another to set a regional, long-term reserve margin to be maintained by LSEs subject to their jurisdiction.

3. When load must be curtailed due to insufficient generation, the transmission provider should avoid curtailing LSEs that have procured sufficient generation, if operationally possible.

H. State Participation in RTO Operations

State commissions have an important role in the process of creating an efficient competitive wholesale market for electricity. The Commission has already established state-federal RTO panels as a forum for FERC and state commissions to discuss issues related to RTO development. However, there currently is no formal process for state commissioners to engage in a similar dialogue with the independent entity that would operate the electric grid under standard market design. The standard market design rule will establish a formal role for state regulators to participate on an ongoing basis in the decision making process of these organizations.

Each RTO or other independent entity that operates the grid should have an advisory committee whose members include state representatives reflecting the breadth of retail customers' interests. The specifics of how this advisory committee would be formed and operate could vary regionally and by RTO.

The standard market design rule will require the establishment of an MMU within the RTO. The MMU will provide reports to the independent governing board of the RTO and the Commission on the efficiency of the markets and the need for rule changes. The MMU should also provide these reports directly to the advisory committee.

Finally, because of the regional nature of these organizations, there are many new issues involving rate design and revenue requirements. We believe the advisory committee can bring a valuable regional perspective to these issues and should play a role in deciding these issues in partnership with the Commission. Once the advisory committees are established, we will work with them to establish protocols for deciding these regional rate issues.

I. System Security

The Standard Market Design and RTO conferences to date have focused on various aspects of market design. System security is critical to the reliable operation of the interstate transmission grid. In this respect, the current OATT defines "good utility practice" as:

> Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. . . .

Similar concerns about reliability led us to require that an RTO must have exclusive authority for maintaining the short-term reliability of the grid that it operates. In a region lacking a Commission-approved RTO, individual transmission operators must perform the same function. The current OATT will be revised to state more explicitly the obligation of transmission providers to comply with all appropriate standards for ensuring system security and reliability.

Infrastructure security of grid equipment and operations and control hardware and software is essential to ensure day-to-day grid reliability and operational security. The Commission will expect all transmission providers, market participants, and generators interconnected to the grid to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

J. Transitional Considerations

We recognize that implementation of a new transmission tariff and standard market design on a nationwide basis may take some time. Standard market design requires many institutional changes and software development. Therefore, the rule will require a phased compliance for standard market design changes in order to implement certain changes as soon as possible. The first phase will focus on a few major points that can be implemented within the existing Order No. 888 open access tariffs fairly quickly. Later phases will involve a full tariff redesign to incorporate all of the elements of standard market design. The first phase will include:

1. Physical trading hubs: Flexibility in choosing resources based on hourly marginal costs is an inherent advantage of network service over point-to-point service, particularly with respect to a merchant generator located in a different control area than the load while competing with the host traditional public utility. Transmission providers that do not offer centralized markets should file a proposal to offer physical trading hubs. Suppliers must be permitted to schedule to physical hubs within the transmission provider's system so that load can choose from a variety of resources, and supply can reach a variety of loads. The transmission charge should be commensurate with the cost of providing the service.

2. Clarifications and updates to the tariff: In the six years since the issuance of Order No. 888, the Commission has clarified numerous provisions in the pro forma tariff. These clarifications should be consistently applied to all existing transmission tariffs. Examples of these are "right of first refusal" time frames and the ability to redirect a long-term reservation. For redirects, competing generators or marketers would be confident that they could attain additional flexibility if the Commission were to revise the pro forma tariff to allow partial term redirects of a long-term point-to-point reservation (i.e., permit a long-term firm point-to-point transmission customer to request alternate firm points for a portion of the contract term and return to the original points later in the term).

3. First Phase tariff compliance time frame: Transmission providers must revise their existing transmission tariffs to include physical trading hubs and clarifications to the Order No. 888 pro forma tariff within 60 days of the date the Final Rule becomes effective.

K. Issues that Need Further Discussion

This paper identifies the general vision for a standard market design for wholesale electric markets and a new transmission tariff. It does not attempt to answer all the questions that will need to be answered to implement the standard market design and write a new transmission tariff. Based on the guidance contained in this document, Commission staff will be developing tariff language for further discussion by stakeholders.

There are many issues involved in the transition to the new services, including: (1) transition of customers under existing contracts to the new Network Access Service; (2) allocation of transmission rights; and (3) development of a schedule for phased compliance and implementation of standard market design. Many of these may need to be decided on a regional basis.

As noted in the discussion of the role of state commissions, there are many rate issues associated with these new services. There needs to be further work on transmission pricing issues, such as who pays for embedded transmission costs, whether postage stamp or license plate rates should be used for existing facilities, and cost allocation for new transmission facilities. All of these issues will require further discussion, with the goal of resolving them as soon as possible.

Finally, this paper envisions that RTOs will have significant responsibilities under standard market design. Consistent with the Commission's November 2001 order, the Commission will use a two track approach to resolve RTO issues. Issues of scope and governance will be handled in individual RTO cases, not in the Standard Market Design rulemaking.

APPENDIX

Electronic Scheduling Collaborative Issues

On October 5, 2001, the Electronic Scheduling Collaborative filed a Status Report on OASIS Phase II Business Practices. The report provided an update on the ESC's efforts to standardize a set of Business Practices for implementation of OASIS Phase II and Electronic Scheduling. As part of that report the Electronic Scheduling Collaborative identified certain issues as candidates for standardization or rulemakings and presented some key policy questions that needed to be answered. As part of the description of standard market design elements in this paper, we have provided preliminary answers to the questions on market design. The questions from the Electronic Scheduling Collaborative and the answers that are contained in this paper are summarized below.

1. Congestion Management -- When Operational Security Violations occur, how is the system to be stabilized in a fair and equitable manner that is nonetheless efficient? Will LMP based systems be standard, or will there be others that must be accommodated?

   Answer: The transmission provider would use market mechanisms whenever possible to deal with potential Operational Security Violations. Thus, locational marginal pricing will be used as the standard method of congestion management. The transmission provider would also develop a security constrained, day-ahead unit commitment and a security constrained real-time dispatch that account for all transmission constraints, such as contingency limits, needed for reliable system operations. Only if these market mechanisms do not stabilize the system will non-market mechanisms be used.

2. Transmission Service -- Are transmission services required to schedule ("covered" schedules only) or are they risk management tools protecting from congestion charges (both "covered" and "uncovered" schedules are allowed)?

   Answer: Anyone wanting to transmit power between two points will need to obtain transmission service. However, Network Access Service could be obtained either well in advance of real time or through the day-ahead or real-time markets. If a customer wants to achieve price certainty (protection from the cost of congestion), it would need to separately procure transmission rights.

3. Loop Flows -- Are contract-path based or flow-based transmission services appropriate? If contract-path based, how are parallel path issues to be addressed?

   Answer: The Network Access Service would be a flow-based transmission service within the RTO. A flow-based system better recognizes the regional nature of the transmission grid.

4. Grandfathered Transmission Service – Should contracts existing prior to RTO development be transferred, or is there an equitable way to retire those contracts? Are there other solutions?

   Answer: This is a transition issue that needs further discussion and may require different regional approaches. Customers under existing contracts should continue to receive the same level and quality of service under standard market design. However, transmission capacity not used by these customers must be made available to others in the day-ahead and real-time markets.

5. Energy Imbalance Markets – How are imbalance markets to function? Will they serve as real-time energy markets (support unbalanced schedules), be limited to supplying needs of imbalance service (require balanced schedules) or will they be required at all?

   Answer: The day-ahead and real-time markets will support unbalanced schedules.

6. Ancillary Services – Will ancillary services be developed in standard ways? Will entities be required to actually schedule ancillary services (required to schedule), or will they be treated primarily as financial instruments (protecting against real-time Provider of Last Resort (POLR) charges)?

   Answer: Ancillary services will be developed in standard ways. Customers will be required to procure operating reserves and schedule ancillary services through self-supply, bilateral transactions, or by paying the market-clearing price in the operating reserves auction(s) run by the transmission provider.

7. Losses – Can we utilize the imbalance markets to support losses? Can we create specific loss standards that facilitate the scheduling process, or must we support methods that are currently in tariffs, but technically unwieldy?

   Answer: The imbalance markets can be used to support losses. New loss standards will be developed and included in the new pro forma tariff.

8. Non-Jurisdictional Entities (NJEs) – How are NJEs to be integrated into the new world? Should systems be designed with the assumption that non-jurisdictional entities will be part of an RTO? Or should they be designed to treat each NJE as a separate entity?

   Answer: This question is not specifically addressed as part of standard market design. However, the Commission's policy is that RTOs should be structured to permit non-jurisdictional entities to voluntarily join RTOs. Issues related to the participation of non-jurisdictional entities in RTOs will be addressed in the individual RTO proceedings.

EXHIBIT PRP-4

Synapse
Energy Economics, Inc.

Best Practices in Market Monitoring

A Survey of Current ISO Activities and Recommendations for Effective Market Monitoring and Mitigation in Wholesale Electricity Markets

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1. Introduction and Summary

Market monitoring and mitigation is widely recognized as an important evaluative tool for understanding the performance, and ensuring the competitiveness, of bid-based regional electricity markets. Both the physical complexities of the electric bulk power system and the administrative complexity of the market rules for competitive wholesale markets contribute to the numerous market failures that have occurred in the four years since FERC Orders 888 and 889 opened wholesale power markets to widespread competition.

The analysis in this report occurs against the backdrop of Order 2000 and its related follow-on orders on specific proposals for Regional Transmission Organizations (RTOs). Most recently, FERC directed the stakeholders in three existing ISOs to engage in a 45-day mediation process to develop a "business plan" for the development of a Northeast RTO that administers a single Northeast market with a single Northeast transmission rate. While approving parts of the individual ISO filings on RTO formation, FERC found that the "size and scope" criteria, one of the four essential characteristics of an RTO, could only be met through a larger Northeast RTO entity. To guide the mediation process, FERC directed stakeholders to use the PJM system as a "platform" from which to build the Northeast RTO, and to supplement the platform with "best practices" from NE and NY.[1]

While we have examined market monitoring procedures in numerous bid-based wholesale markets, we have focused primarily on the three northeast ISOs and to a lesser extent California.[2] For the United States, these ISOs have had the most substantial experience with bid-based markets. Due to FERC's recent RTO Orders, the three northeast ISOs are a natural focus as plans to implement a Northeast RTO are considered. NY and NE have much more extensive monitoring activities (in part due to their bid-mitigation authority), which PJM may want to consider as enhancements to its own processes, whether in the context of a Northeast RTO, or for direct application to the markets that PJM currently administers.

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[1] On September 17, 2001, the FERC Administrative Law Judge in charge of the 45-day mediation issued his Report together with a Business Plan for the formation of a Northeast RTO. FERC allowed comments on the Report to be filed through October 9, 2001. It is anticipated that FERC will issue an Order on the Report in early November. The Business Plan identifies numerous issues related to Market Monitoring, but does not make any substantive recommendations.

[2] We looked briefly at the Texas ISO and the proposed Midwest ISO but did not evaluate either one in detail due to the limited market experience of Texas and the absence of market experience for the Midwest ISO. Internationally, we examined the markets in the United Kingdom, Nord Pool (Norway, Sweden, Finland, and Denmark), Germany, and Australia. A summary of this review is attached as Appendix B.

responsibility to ensure that markets are workably competitive both in real-time and in the longer-term.

Recommendation #1: The MMU must closely monitor, and ideally be physically present or adjacent to, the control room dispatch.

Recommendation #2: The MMU should report within the RTO to the Board of Directors. The MMU should work closely and collaboratively with the CEO and the RTO staff that has market design responsibilities.

Recommendation #3: The RTO should contract with an independent Market Monitor (IMM) or Market Advisor to complement and advise an internal MMU. The IMM should report directly to the Board of Directors of the RTO.

The market monitor should monitor and have all the tools necessary to monitor all RTO/ISO markets as well as related energy markets and markets outside the region during all hours.

Recommendation # 4: The MMU should be responsible for monitoring all wholesale markets administered or facilitated by the RTO/ISO, including the spot and bilateral energy, ancillary-services, capacity, and transmission markets. The MMU should monitor both supply and load bids in all markets.

Recommendation #5: As part of its ongoing evaluation of market efficiency and competitiveness, the MMU should evaluate the performance of the markets against the outcome of a market where all bids are at marginal cost.

Recommendation #6: The MMU should have the authority to assess the impact on the market of proposed mergers and acquisitions, and be a party to such proceedings.

The market monitor should have authority to mitigate, sanction, and penalize, as well as the ability to identify necessary rule changes.

Recommendation #7: The MMU should have access to all data that will assist it in performing its market monitoring function.

Recommendation #8: The MMU should have authority to mitigate any bid in any market prior to accepting it.

Recommendation #9: Bid caps should be used as an essential component of electricity markets.

Recommendation #10: In addition to its authority to mitigate a bid in advance of accepting it, the MMU should also have the authority to impose sanctions or penalties on market participants for specific behaviors, including the failure to provide information requested by the MMU.

Recommendation #11: The MMU should have the authority to flag clearing prices and make price corrections for a limited period of time after the market clears.

Recommendation #12: The MMU should have the authority to file with FERC for changes to both market-monitoring rules and market rules.

The market monitor should encourage transparency in both the marketplace and in its own activities through regular reports.

Recommendation #13: In order to improve transparency and enhance confidence in the markets, the MMU should regularly and frequently issue detailed reports on its monitoring activities.

Recommendation #14: Bid data with names should be released on a one-month lag.

In conclusion, our review of current market monitoring and mitigation practice indicates that market monitoring activities need to be broadened and enhanced to guard against significant anti-competitive activities by market participants, including exertions of market power. Of particular importance is our observation that bid-based market systems do not produce prices that are "just and reasonable" when demand approaches or exceeds available supply.[3] The market monitoring improvements identified in this report are needed now and are not dependent upon any specific proposals or alternatives currently being discussed in the context of the Northeast RTO mediation process. In fact, a strong argument could be made that enhanced market monitoring and mitigation practices are a pre-condition for the creation of a single Northeast energy market.

2. Experience and Trends in Market Monitoring

2.1 The Need for Monitoring of Electricity Markets

With economic deregulation of wholesale electricity markets, there is an urgent need for aggressive market power monitoring and mitigation. In markets for other commodities, we rely upon the responsible state and federal agencies to promote workably competitive markets through enforcement of antitrust laws. Actions can be taken by antitrust

[3] Throughout this text we use the term "demand" to mean electrical requirements including reserve requirements, and the term "supply" to mean generation and operating reserves. Our focus on times when demand approaches or exceeds available supply does not imply that market prices are necessarily just and reasonable at other times. Indeed, there may be significant opportunities for market manipulation during less constrained times.

authorities in situations with collusion, proposed mergers, or monopolies. In electricity markets there are several compelling reasons that this customary approach is not adequate or prudent.

First, the electric industry is in a transitional period, with many decades of experience as regulated monopolies. The existing companies are large, with infrastructure designed and built to serve customers in transmission system control areas where there was no need to consider promoting competition. There was an extraordinary degree of industry cooperation – with individuals routinely participating on committees to coordinate system expansion and operation (e.g., the North American Electric Reliability Council). While this was appropriate and necessary in the past, going forward there are inherent tensions between the benefits of coordination and the need for firms in a deregulated market to act competitively. With respect to market power monitoring and mitigation, it is useful to keep in mind that most of the individuals currently working in this industry come from a tradition of cooperating monopolies. Market participants have, for example, played a very active role in designing and modifying electricity market rules in the new ISOs. While this may have occurred for legitimate reasons, it does point to the need for market monitoring and mitigation by an independent entity.

Second, the role of electricity as a fundamental element of the infrastructure supporting the economy as well as basic human activities should be considered. Events in California have illustrated the need for reliable electricity service at reasonable prices, and the implications to local and regional economies of power outages and sustained wholesale prices above competitive levels. It is not an easy task to sort out the specific roles of particular underlying factors (e.g., capacity shortages vs. anti-competitive withholding of generation) in the California debacle. Still, it is clear that the exercise of market power played some substantial role in causing California's problems and that aggressive, timely, and effective market power monitoring and mitigation would have been helpful.

Third, a combination of physical characteristics of electricity generation and transmission make market power a particularly urgent concern in electricity markets. Specifically:

- Electric power must be delivered over a constrained transmission grid,
- Electricity supply and demand must be balanced on an instantaneous basis, and
- Storage of electricity is limited, inefficient and expensive.

Even in electricity markets where generation ownership is not concentrated as a general matter, there are likely to be locations ("load pockets") and times for which there are an insufficient number of competing generators.

Fourth, electricity markets are characterized by repeated organized interaction, with bids typically submitted on a daily basis, and refinement on an hourly basis (in "day-ahead" and "real time" markets). Markets that function as a repeated game are particularly subject to tacit collusion, as participants learn about and react to the bidding strategies of other participants, or even use the bidding process to communicate and promote cooperation (see, for example, Gibbons 1992).

Fifth, market entry is difficult in electricity markets. It can take several years to get a power plant built, given difficulties in siting, obtaining permits and financing, lining up fuel supply, and construction. Power generation is capital intensive, with new combined-cycle gas plants costing in the neighborhood of $600/kW. In other markets, where market entry is quicker and less costly, actual market entrants or even the threat of entry may be relied upon to moderate the exercise of market power. In electricity markets, the role of market entry must be supplemented by effective market monitoring and mitigation.[4]

And finally, the lack of demand participation in electricity markets is noteworthy and troublesome. In the short run, electricity demand is almost entirely "inelastic." That is, when pool prices spike there is little practical opportunity for customers to cut back purchases. This is changing gradually, with demand-response programs being developed and expanded in all of the operating ISOs (Synapse 2001) but we are still many years – probably decades – away from an adequate demand response in electricity markets. In the meantime, aggressive market monitoring and mitigation supplemented by bid caps will be essential elements of electricity markets.

In electricity markets, the continuing obligation of generators to serve loads (either under contract or as a continuing obligation of a vertically integrated company) can help to decrease or eliminate the incentive for a company to bid above marginal costs in order to raise the market price. In PJM, unlike California and New England, a large amount of the generating capacity has continued to be owned by companies with substantial load obligations. As PJM's 2000 State of the Market Report notes:

> The structural analysis indicates that the PJM control area exhibits moderate market concentration. However, specific areas of the PJM system exhibit moderate to high market concentration that may be problematic when transmission constraints exist. There is no evidence that market power was exercised in these areas in 2000, primarily due to the load obligations of the generators in those areas, but a significant market-power related risk exists going forward should those obligations change.[5]

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[4] For a discussion of market entry, as well as an excellent overview of experience in electricity markets through the beginning of 2000, see "Horizontal Market Power in Restructured Electricity Markets" (DOE, 2000).

[5] PJM 2000 State of the Market Report, p. 11.

2.2 Regulatory Context

Orders 888 and 889

In Orders 888 and 889, issued in April 1996, FERC introduced new opportunities for competitive markets to replace traditional cost-based regulation of wholesale bulk power systems. As a result of those Orders, FERC set a series of events in motion that have led to both the need for a report such as this one and to many of the practices that this report recommends. In its April Orders, FERC required that:

- All owners of transmission systems had to file an Open Access Transmission Tariff (OATT) that would provide universal and non-discriminatory access to the use of the bulk power electric system for wholesale electricity sales.

- Electric utilities were allowed and encouraged to develop proposals for "independent system operators" who could oversee the implementation of the OATT on a fair and impartial basis and who could administer a wholesale market in a manner, subject to FERC approval, that would produce "just and reasonable" rates.

Despite FERC's concern that market based rates might provide an opportunity for the exercise of "market power" by owners of generation resources, FERC stated that it would approve market based rates upon satisfaction that the exercise of market power was either unlikely, or that structures had been proposed to guard against such exercises. From this initial posture of "let's see how it goes," FERC has approved a series of increasingly more detailed and complex market monitoring proposals over the ensuing years.

Order 2000: RTOs

In December 1999, FERC issued Order 2000, which required all entities that implement open access transmission tariffs to file proposals for creating a regional transmission organization (RTO) that satisfied the four characteristics and eight functions detailed in the Order.[6] Filings were required in October 2000 for transmission tariff entities that were not part of an existing ISO; the ISO transmission entities were required to make their filings in January 2001.[7]. For the purposes of this report, the second characteristic, independence, and the sixth function, market monitoring, deserve particular attention.

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[6] The four characteristics are (1) independence from market participants, (2) appropriate scope and configuration, (3) operational authority, and (4) short-term reliability. The minimum functions pertain to (1) transmission service and tariff, (2) congestion management, (3) parallel path flow, (4) ancillary services, (5) transmission availability information, (6) market monitoring, (7) transmission planning and expansion, and (8) interregional coordination. Regional Transmission Organizations, Order No. 2000, 89 FERC ¶ 61,285 (December 20, 1999).

[7] PJM and the transmission owners filed their RTO proposal early, on October 11, 2000.

FERC highlighted the need for RTO independence from market participants to ensure that the wholesale electricity markets and the associated transmission service would not be subject to manipulation or undue influence from entities engaged in profit-making activities. A truly independent RTO would create confidence among market participants that there was a level playing field; it would also encourage new entrants into both the market and transmission functions of the wholesale regional marketplace.

FERC identified market monitoring as one of the core functions that an RTO entity must provide. Since Order 888, FERC has moved toward a more active approach with regard to the need for and benefits of market monitoring. However, FERC still maintains a very flexible approach to market monitoring by allowing RTO participants to identify appropriate market monitoring activities that would meet certain broad standards.

Northeast RTO Orders

In its Orders released in July 2001, FERC discussed how the filings from PJM, NY and New England addressed the "independence" characteristic and the "market monitoring" function. The orders are briefly summarized.

Independence

In the PJM Order, FERC found that PJM meets the independence characteristic except for the establishment of reliability requirements (including capacity resource obligations and capacity deficiency requirements) pursuant to the Reliability Assurance Agreement. For determining reliability criteria under the RAA, FERC stated that PJM can not allow these requirements to be set by a committee of market participants. In this Order, FERC did not specifically address the role that market participants have under the PJM Operating Agreement in proposing and approving changes to the market rules.

In the NYISO Order, FERC found that the authority of market participants, through a governance committee, to review and approve all changes to the wholesale markets system was inappropriate and created "undue influence" on the part of market participants. FERC found that NYISO's RTO proposal failed to meet the independence characteristic.

In the ISO-NE Order, FERC found that market participants' role in governance, through the NEPOOL committee process, was inappropriate. In an RTO, a committee of market participants, such as NEPOOL, should serve a purely advisory role. FERC specifically mentioned NEPOOL's role in approving changes to market rules and stated that this should be the exclusive authority of ISO-NE.

Market Monitoring

The implications of the Orders for market power monitoring and mitigation are not clear. FERC emphasizes that it will be paying close attention to, and will be involved in, ongoing efforts to monitor markets. FERC found that all three proposals satisfied the market monitoring function, although ISO-NE must make a supplemental filing once it has implemented a congestion management system.

It is worth noting that the market monitoring plans of the three Northeast ISOs differ significantly. PJM's market monitoring unit has a small staff and no general authority to mitigate bids or impose sanctions and penalties; it performs primarily a monitoring function, only. However, PJM has the authority to cap bids of must-run units in local load pockets, which is done outside of the market monitoring process. FERC states in the PJM Order that it is not essential for an RTO to have mitigation authority, and accepts PJM's proposal, which does not include a request for mitigation authority.

ISO New England currently has bid mitigation authority that was won with a strong effort on the part of PUCs and AGs in New England. ISO-NE has a medium sized staff and the authority to mitigate bids before the market clears, impose sanctions and penalties, and also mitigate congestion payments for generators in "non-competitive" conditions.

In the New York Order, FERC approved the NYISO's proposal and specifically mentioned the appropriateness of its market mitigation and sanctioning authority. NYISO has the largest staff and the most extensive monitoring and mitigation process of the three ISOs. Furthermore, NY and NE have "outside" market advisors – entities that advise the ISO Board but are not within the ISO corporate organization, while PJM does not.

The disparity in market monitoring authorities and practices is important, and FERC has not given any clear guidance on how the market monitoring function should be designed for the Northeast RTO. Since FERC identifies PJM as the platform upon which the Northeast RTO should be developed, it remains unclear as to whether there will be consistency between the market monitoring functions of the three control areas. While best practices of other ISOs are to be incorporated into the PJM market platform, FERC has not clearly stated how the NE RTO market monitoring function is to be designed nor identified any of the market monitoring "best practices" from NY and NE that should be added to PJM's RTO proposal for market monitoring.[8]

2.3 ISO Experiences

Market Monitoring Concerns during ISO Formation

As the ISO's were established in the Northeast electrical control regions, each took a slightly different perspective on the need for, and implementation of, market monitoring.

PJM's proposal for market based rates for a multi-state tight power pool included a study by independent economists that PJM's markets were not "concentrated" and there was unlikely to be an opportunity for existing generators to have or exercise market power.

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[8] FERC, *RTOs – Administrative Law Judge Mediator's Report to the Commission*, Docket No. RT01-99, September 17, 2001, p. 7.

Despite some protests by intervenors in the FERC proceeding, FERC agreed in large part with PJM's claims.[9] At the time of market implementation PJM had only a small market-monitoring unit with no mitigation authority and no authority to impose sanctions. However, PJM required cost-based bidding for the first year of the markets, as well as a bid-cap of $1,000 that is still in effect. In addition, PJM had the authority to manage prices in load pockets by capping the bids of must-run generation. Furthermore, due to the limited amount of divestiture of generation units, most owners of generation had significant load obligations, which would act as a restraint on bids.

In New England, market participants also asserted that market power concerns were minimal. As part of its filing for market based rates, the New England Power Pool ("NEPOOL")[10] included a study by independent economists that found that under most scenarios, the New England wholesale market was not constrained and that concentrations of generation ownership were not so high as to warrant concerns about the possession or exercise of market power. In response to intervenor comments that challenged NEPOOL's study, however, FERC ordered NEPOOL, the new ISO, and state regulatory agencies to develop a market rule that would allow for appropriate and effective market monitoring and mitigation, including the authority to impose sanctions on market participants.[11]

New York filed its proposal for market-based rates after PJM and New England. As part of its proposal, NY included a market-monitoring unit within the ISO and an independent Market Advisor who sat outside the ISO and reported directly to the ISO Board. FERC approved this arrangement in late 1999.

Post-formation ISO Experiences

As ISOs and market participants have gained experience with electricity markets, and as those markets have evolved over the past few years, ISOs and other stakeholders have modified and sought to improve market monitoring practices and procedures. Comparison of these experiences provides an initial basis for identifying necessary components of effective market monitoring authority and procedures.

In this Section we will discuss key aspects of the experience of the four ISOs in the US that have been up and running. We will also describe some of the more notable market failures and problems that have occurred in each of the four US ISOs. We begin with

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[9] 86 FERC 61,248, March 10, 1999.

[10] NEPOOL consists of the owners of the generation and transmission facilities in the New England control area, as well as the participants in the wholesale markets and various other stakeholder entities.

[11] The immediate result was MRP 17 (Market Monitoring and Mitigation), but MRP 13 (Sanctions) and MRP 15 (Price Correction Authority) also reflect the directives in FERC's Order

California because it was the first to institute a competitive, bid-based wholesale market.[12]

California

There has been an on-going effort to ensure that prices in California's electricity markets are consistent with efficient competition. California experienced problems with its ancillary services markets right from the beginning. Bid-caps were imposed in 1997/98 in an effort to control exorbitant prices. The energy market experienced problems due to the limited transfer capability of the transmission system, particularly between Northern and Southern California. Price caps were relaxed, as the problems were resolved.

In 1999 and 2000, the problems in the energy market became so severe that $1,000 prices and rolling blackouts began occurring with regularity. Since the beginning of the competitive wholesale markets in California, CA ISO (through its Department of Market Analysis "DMA" and its Market Surveillance Committee "MSC") has closely examined the wholesale markets in California. Prior to the spring of 2001, CA ISO primarily identified the potential for market manipulation under a variety of circumstances and sought structural fixes to prevent the potential for exercise of market power. Similarly, FERC staff studies and FERC Orders state in broad terms the potential for the exercise of market power and that it appears market power has been exercised.

In contrast, in spring 2001, CA ISO analysis identified specific evidence of the exercise of market power by specific market participants in filings in docket EL00-95. Simultaneous with FERC's investigation of specific bids above the soft cap established in December 2000, CA ISO analyses established links between bidding behavior of specific market participants and non-competitive prices in California markets. Reports from March 2001 are based on specific findings regarding specific market participants and are the first reports to establish a link between individual bidding actions and their impact on market prices. These findings are supplemented in an April analysis. Both the March and April analyses make allegations against specific market participants (whose identity is held confidential). ISO submitted confidential analysis and data to FERC in support of its conclusions. These analyses are submitted in response to FERC's desire to implement prospective market monitoring, and FERC's Section 206 investigation of just and reasonable rates for the period beginning December 8, 2000; however, the analysis covers a period beginning in early 2000 and the ISO emphasizes the need to consider refunds prior to the period that FERC has identified.

In late spring 2001, FERC developed a prospective market monitoring and price mitigation plan for California. The plan, for real-time California wholesale electric markets, included the following: (1) enhanced ISO ability to coordinate and control

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[12] Nonetheless, California stands apart from the other ISOs due to the uniqueness of its market structure. PJM, NE and NY are much more similarly structured in their market designs, despite the significant differences that do exist between.

planned outages, (2) must-offer obligation for generators, (3) conditions, including refund liability, on sellers' market-based rate authority, (4) price mitigation in California and throughout the rest of WSCC during periods of reserve deficiency; (5) price mitigation in California and the West during periods of non-reserve deficiency, and (6) weekly ISO reports to FERC on schedule, outage, and bid data for all hours.[13] The price mitigation is to be achieved through bid caps. During periods of reserve deficiency, there will be a single market-clearing price established using proxy prices for each generator. Bids above the proxy price are permitted but must be justified and are subject to refund.[14] During periods of non-reserve deficiency, bids cannot exceed 85% of the highest market-clearing price during the most recent period of reserve deficiency.[15] Due to aggressive efforts in early 2001 to encourage conservation, energy efficiency, and develop initial load response programs, the decision by FERC to allow soft price caps, and below average summer temperatures, the summer of 2001 did not repeat the high prices and scarcity problems of the previous winter.

PJM

There are a number of structural and design features of the PJM wholesale market that, in combination, have served to curb systematic abuse of market power since the ISO's implementation of market-based rates in April of 1998. In particular, the opportunity to profit from market abuse has been severely limited by the fact that the bulk of the generation capacity has been dedicated to serving retail load at regulated or capped rates.[16] In addition, the requirement to bid at cost during the first year of operation, along with the phased opening of product markets, curtailed opportunities to exploit design flaws during the initial "shake-out" of the PJM markets. Finally, the PJM market design incorporated at its outset a bid cap in the energy market of $1,000 per MWh, an effective price cap in the capacity market at the Capacity Deficiency Rate, and authority to cap energy bids at cost for generators located in local load pockets.

However, the current relationship between generation ownership and load obligations is changing. More utilities are choosing to divest generation resources and arrangements for providing standard offer service under capped prices are expiring. In addition, the cost capping of bids in load pockets applies only to units built prior to July 1996. Over

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[13] Docket No. EL00-95-012 et al., April 26, 2001, 95 FERC 61,115. Docket No. EL00-95-031 et al., June 19, 2001, 95 FERC 61,148.

[14] 95 FERC 61,115 (April 26, 2001)

[15] 95 FERC 61,148 (June 19, 2001)

[16] The continued obligation to serve load is a significant deterrent to behavior that would raise the market-clearing price. A utility that owns generation and has a significant load obligation is not in a position to profit from raising the market-clearing price to the extent that an independent generation company would be. The additional income for the generation resource would be offset by higher costs to supply its load (generally retail customers) and an inability to pass through those costs due to fixed rates or cost-of service regulation.

time, with new additions, the proportion of capacity exempt from cost capping will grow. However, at the November 8, 2001 meeting of the PJM Energy Markets Committee, the PJM market monitor made a proposal to collect cost data from units built subsequent to July 1, 1996, and there are stakeholder discussions underway in PJM to consider cost capping those units.

Despite the structural relationships that limit the value of manipulating prices, and rules that limit the ability to do so, the PJM markets have not been immune to the exercise of market power or gaming of market rules. Since its inception, the PJM MMU has addressed occurrences of opportunistic bidding in the energy market on high-demand days, efforts to circumvent the $1000 cap in the energy market, abuse of market power in the installed capacity market, and complaints regarding the potential for gaming in the FTR market.

Since 1999, the PJM energy market has experienced price spikes on some days where load approaches or exceeds available supply from internal resources. For example, on July 28, 1999 the market price hit $935/MWh, or more than seven times the $130/MWh marginal operating cost of the highest-cost unit on the PJM system.[17] More recently, real-time prices rose above $900/MWh every day from August 7 through August 9 of 2001. In the former case, the PJM MMU found that

> It appears clear that some generation owners, with an incentive to raise the price, did attempt to exercise market power by economically withholding the output of some units. It is also relatively clear that on July 28 the result was to increase the price of energy above the competitive market level.[18]

In the more recent case, the MMU is continuing to evaluate whether market power was exercised.[19]

In addition to these isolated occurrences of apparently anti-competitive bidding, the MMU has occasionally uncovered evidence of systematic gaming of market-design flaws. For example, the MMU identified attempts to circumvent the $1,000 bid cap with minimum run time bids. In response, the MMU implemented modifications to the rules regarding payments to minimum run time generators that foreclosed further gaming opportunities of this type.

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[17] In fact, prices exceeded $130/MWh in 96 hours, 4.3% of the hours, of the summer of 1999 (source: PJM *State of the Market Report: 1999*, page 11). According to one study, PJM energy-market costs exceeded marginal operating costs by $224 million during the summer of 1999. See Erin T. Mansur, "Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market", University of California Energy Institute, April 2001, p. 1.

[18] PJM, *State of the Market Report: 1999*, page 36.

[19] PJM, *PJM Prices and Markets: The Week of August 6, 2001*, Preliminary Report, August 21, 2001, p. 1.

PJM administers a separate market for regulation services. Although the regulation market has experienced intermittent price spikes since its inception in June 2000, the MMU has not identified specific instances of bidder gaming of market-design flaws.

Over the last few years, PJM's installed capacity market has been plagued with the problem of daily de-listing of capacity resources. The MMU has consistently determined that such de-listing represents a rational competitive response to high market prices in regional markets bordering the PJM control area. However, because of the potential impacts on system reliability from daily de-listing, the MMU has recommended, and FERC has approved, implementation of a seasonal capacity market beginning in the summer of 2001.

One notable instance of the apparent exercise of market power in the installed capacity market occurred in the first quarter of 2001, when prices rose from approximately $2/MW-day in the prior quarter to $177/MW-day (i.e., the ceiling on capacity prices set by the Capacity Deficiency Rate –"CDR") during a period when there was excess capacity on the system. The MMU identified a flaw in the mechanism for distributing deficiency payments received from load-serving entities that are short on capacity as the cause of the run-up in prices. Since such payments were distributed to capacity owners that were long on capacity, owners that were sufficiently long had a perverse incentive to bid at the CDR. If such bids were accepted, then the market price received by the bidders would be at the CDR. Alternatively, if such bids did not clear, then the pool would be short, and the long owners would be paid the CDR anyway. In response to this design flaw, the MMU devised and implemented a new mechanism for distributing deficiency revenues that eliminated the opportunity to profit from bidding at CDR when the market is long.

Finally, the MMU has received complaints with regard to gaming in the Financial Transmission Rights ("FTR") auctions by transmission owners through the withholding of data on planned transmission outages that can affect FTR prices. Although the MMU has not uncovered evidence of such incidents, it recommended that rules regarding outage notification be strengthened.[20] Revisions to market rules governing outage notification were approved by the PJM Operating Committee.

ISO-NE

Since the inception of ISO-NE in July 1997, there has been an iterative and often very contentious process of refining and modifying ISO-NE's market monitoring and mitigation authorities through a series of market participant votes and FERC proceedings. While ISO-NE began with broad authority to correct prices as markets were launched, that authority has gradually been reduced so that it is currently restricted to revising

[20] FERC, however, issued a show cause order to determine whether PECO Energy may have given its unregulated affiliates preferential access to information that was helpful to the affiliates in bidding for FTRs (97 FERC 61,009, Docket No. IN01-7, October 3, 2001).

prices for computer software and human errors, only.[21] ISO-NE and market participants have also struggled to determine what circumstances prevent a market from being workably competitive. Specifically, this issue has been argued regarding system-wide capacity constraints, inappropriate market products, and load pockets. ISO-NE has used a variety of tools to address identified concerns with the competitiveness of the markets including recommending changes in market structure and design, recommending changes in market rules, using its emergency rulemaking authority, mitigating bids, flagging and correcting prices, and imposing sanctions on market participants.

The wholesale markets implemented in May 1999 allowed unrestricted bidding in seven markets: an energy market, four ancillary services markets, an operable capability market, and an installed capacity market. In the first weeks there were problems with generation units (mostly hydro) that bid below the Energy Clearing Price ("ECP") but were not being dispatched due to conflicts between bidding and operational (reliability) rules. As that problem was being addressed, unusually warm June weather triggered a series of capacity deficiency events that led to more conflicts between operational rules for reliability and bid-based market rules.[22] ISO-NE filed emergency rule amendments in June and July 1999, to address most of these issues. In August 1999, ISO-NE filed for elimination of the Operable Capability market as a redundant and unnecessary market. Despite vociferous protests from owners of generation, FERC approved ISO-NE's filing. On numerous occasions during that first summer, ISO-NE observed that on days when load approached or exceeded New England supply, prices in its energy, three reserve, and operable capability markets were routinely at levels significantly above those that would be expected from a workably competitive market, the Market Rule 15 standard. In response to this observation, ISO-NE requested and received from FERC a 60-day extension of MRP 15.

In the fall of 1999, FERC denied ISO-NE's request for a second extension of the price correction authority of MRP 15. FERC stated that the extensive price correction authority in MRP 15 was only intended for the initial 90-day market start-up period and that after an additional 60-day extension, it would not be further extended. FERC concluded that any changes to the market designs should be implemented through market rule filings by NEPOOL or, if needed on an emergency basis, by ISO-NE. FERC agreed,

[21] Prior to the implementation of the markets, FERC approved Market Rule and Procedure (MRP) 15. MRP 15 authorized ISO New England to flag and correct prices that "were inconsistent with a workably competitive market". MRP 15 was an interim rule (90-day sunset provision) to address problems with the design and implementation of market-based rates. Although MRP 15 is still in effect, the scope of the rule has been severely limited and the "workably competitive" standard has been eliminated.

[22] Similar to the problems in the first few weeks, the conflicts had to do with units that were "postured" (held in reserve) due to their quick response capability or limited energy availability (ponded hydro) despite the fact that their energy bids were in merit and under normal circumstances they would be dispatched for energy. The original rules had restrictions on when units were eligible to set the energy clearing price, when they could receive uplift compensation, and the manner in which units could be designated for reserves.

however, with ISO-NE's observation that due to market failures during times of capacity deficiency, the reserve market prices could not exceed the ECP.

In July of 2000, in response to a complaint from a load serving utility (one that has divested all its generation resources) about the $6,000 ECP price spikes in May, FERC capped bids at $1,000 per MWh. The complaint argued, in essence, that a market-based system did not operate properly during a capacity deficiency event. That bid cap continues today, as does a cap on ancillary-service prices.

Just as ISO-NE has gone through several iterations in modifying its price revision authority, it has gone through several stages in determining the appropriate authority and circumstances during which bid mitigation should apply. There are two occurrences that offer a striking example of the obstacles to effective market monitoring and implementation of corrective policies under current MMU rules and ISO practices.

May 2000

The May 2000 event involved dispatchable energy contracts that were associated with installed capacity (ICAP) entitlements. Under then existing rules, a NEPOOL Participant could receive credit in the monthly ICAP market for ICAP entitlements associated with a contract to supply energy even if the energy contract never flowed. The energy contract would have to be bid into the market every day and be available to flow (dispatchable) if called. Due to flaws in the design of the ICAP market, some NEPOOL Participants were removing ICAP offers from the bilateral market and thereby "forcing" other NEPOOL Participants to purchase ICAP requirements through the ISO administered residual spot market (which settles after the month) at significantly higher prices. In January, February, and March of 2000, ISO New England mitigated bids in the spot market after determining that the extremely high bids were, in effect, economic withholding.[23]

Several NEPOOL Participants began submitting external dispatchable contracts with extremely high energy bids in early 2000 as an alternative way to receive ICAP credit, rather than entering into a New England bilateral contract or relying on the post-month spot market. By submitting contracts with high energy bids (some as high as $10,000 per MWh), the Participant was relatively certain that the contract would never flow, but the ICAP value would be credited. ISO New England commented on this "practice" in its FERC filing.[24] In that filing, ISO New England noted that the external contracts with extremely high energy prices could be called if a capacity deficiency event occurred. On May 8th, unseasonably warm weather created extremely high demands at a time when numerous generation units were unavailable due to spring maintenance. That morning, ISO New England had dispatchable contracts in its bid stack at prices as high as $10,000. Around noontime, as New England approached a deficiency in capacity, a $6,000 bid was

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[23] Docket No. EL00-62-000, ISO-NE filing of 5/8/00.

[24] Id. Prior to January 2000, the ISO administered spot market had cleared at $0 per MWh for the previous seven months.

dispatched and set the ECP for the next four hours. In a subsequent report, ISO-NE stated that based on prices in the NY market, it had determined that the $6,000 bid was "reasonable" and accepted it without mitigation.[25]

In response to widespread criticism of the ISO's decision to accept the $6,000 bid, ISO New England maintained that the market rules then in effect had been properly implemented. It described in detail how the rules allowed such contracts, that the contract in question met the rule requirements, and that ISO New England had an obligation to implement the rules without regard to price.[26] ISO New England proposed changes to the market rules to prevent recurrences without resorting to bid or price caps. In July, FERC adopted some of the ISO's proposed changes while installing a $1,000 bid cap and stating that markets are not competitive during capacity deficiency events.[27]

Summer 2001

On June 1, 2001, the NEPOOL Participants Committee (NPC) approved changes to the market rules to prohibit external dispatchable contracts from setting the ECP. Under the new rule, external contracts would be eligible to receive payment based on their bid prices, but would not be eligible to set an ECP that would be paid by all spot market purchasers. On June 14th, several NEPOOL Participants appealed the NPC decision to the NEPOOL Review Board, thus staying any NEPOOL action.[28] On July 10th, ISO New England filed the rules changes with FERC and requested an effective date of September 1, 2001.

On July 23, 2001, the New England bulk power system experienced a sudden loss of generation resources, which coupled with high loads due to warm weather, created an almost immediate capacity deficiency situation. ISO New England accepted all available bids, including an external dispatchable contract bid at $1,000/MWh. The ECP was set at $1,000 by that contract for two hours on Monday, July 23; for four hours on July 24; and for seven hours on July 25. ISO-NE evaluated the significant differences between the ECPs set by the external contracts and the ECPs without those contracts. The total increased cost for spot market energy in the 13 hours of $1,000 ECPs was estimated by ISO-NE to be $80 million.[29] The fundamental issue is how five-minute price increases of

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[25] ISO-NE noted that marginal prices in NY on the morning of May 8th exceeded $3,300 per MWh. Pursuant to agreements with the NY ISO for purchases of emergency power, ISO-NE would be obligated to pay 1.5 times the NY marginal price. ISO-NE reports "Events of May 8-9, 2000" (June 1, 2000) and Supplemental Report on May 8, 2000" (July 28, 2000).

[26] Id.

[27] 92 FERC 61,065 (July 26, 2000).

[28] Pursuant to NEPOOL's rules, an appeal to the NEPOOL Review Board stays the filing of rule changes approved by the NPC until the Board renders a decision.

[29] ISO Customer News, Issue #70, August 15, 2001; NPC Operations Report, August 3, 2001.

500 to 2000 percent can be the result of a properly functioning competitive market. There is also a concern as to why ISO-NE allowed the external dispatchable contracts to set ECPs on the 24th and 25th after being alerted to the situation on the afternoon of the 23rd. Given that a rule change that would have corrected this situation had already been filed with the FERC, ISO-NE could have used its emergency rule-making authority to implement the pending rule immediately.

In a report released in September, ISO-NE determined that the $1,000 prices were appropriate because they were consistent with the rules then in effect. This response is the same as the response to the May 2000 event and does not answer the question of whether the rules themselves are consistent with efficient and competitive markets.

In the two events described above, ISO New England chose not to exercise its explicit authority in the Interim ISO Agreement to ensure the "competitiveness and efficiency" of the wholesale markets.[30] Section 6.17(e) of that agreement states:

> If the ISO determines in good faith that (i) the failure to immediately implement a new System Rule or Procedure or a modification to the existing System Rules or Procedures would substantially and adversely affect (A) System reliability or security, or (B) the competitiveness or efficiency of the NEPOOL Market, and (ii) invoking the rulemaking procedures of the relevant NEPOOL Committee would not allow for timely redress of the ISO's concerns, the ISO may promulgate and implement such new or modified System Rule or Procedure unilaterally upon written notice to the NEPOOL Executive Committee, subject to approval by the FERC, if required.

Underscoring the importance of ISO-NE's responsibility to ensure the reliability, competitiveness, and efficiency of the wholesale markets, any rule changes implemented pursuant to this authority can become effective immediately, rather than the mandatory 60-day waiting period associated with rule changes that NEPOOL files with the FERC. While it is important to administer market rules in a consistent and even-handed manner, it is also important to change rules once they are observed to produce anti-competitive impacts.

It is important to note that FERC has not demonstrated consistent support for the ISO's execution of its authority pursuant to Section 6.17 of the Interim Agreement. In November 1999, FERC specifically referred to the ISO's emergency rule-making authority as one of the reasons that price correction authority under MRP 15 for market design flaws should be eliminated.[31] However, in a subsequent Order in July 2000,

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[30] The Interim ISO Agreement is the document in NEPOOL's 1996 FERC filing that details the relationship between NEPOOL, comprised of market participants, and ISO New England, the independent system operator.

[31] 89 FERC 61,209 (November 23, 1999).

FERC criticized ISO New England for having to resort to its emergency authority rather than achieving rule changes through the NEPOOL Committee process. FERC also directed ISO-NE to revise MRP 17 to "reduce the level of ISO discretion in determining when to apply mitigation measures."[32]

The very complex, and often very difficult, evolution of ISO-NE's market monitoring authority and practices has highlighted an increasingly sophisticated understanding of electricity markets and the conditions that permit, or hinder, "workably competitive

NYISO

Perhaps as a result of the decision to implement several bid-based markets simultaneously, there have been some notable instances of opportunistic bidding behavior since the startup of the NYISO in late 1999. In response to these problems, over the last two years the NYISO has implemented bid caps and enhanced bid mitigation procedures in the energy market, suspended market-based pricing and subsequently imposed bid caps in the reserve market, and expanded the scope of the mitigation mechanisms applicable to New York City generators.

In the energy markets, a bid cap of $1,000/MWh was implemented in July of 2000 based on a proposal by the New York PSC and following the filing of a complaint by New York State Electric and Gas that called for imposition of cost-based bidding. Plagued by numerous design flaws in the first few months of operation, the NYISO Board requested FERC approval of a temporary bid cap in expectation of continuing problems in the upcoming summer period. Although initially proposed as a temporary measure, the ISO has repeatedly requested and been granted extensions of the bid cap.

The market-monitoring plan adopted at the end of 1999 authorized the MMU to mitigate energy bids that exceeded certain pre-determined thresholds. When first implemented, the MMU employed a manual procedure for flagging and mitigating bids that was too cumbersome to allow for mitigation of bids prior to their use in determining the market-clearing price for the current operating day. Instead, the MMU was constrained to applying the mitigated bid for determining price for the following day. Because of this one-day lag in mitigation, a generator could reap, and consumers would be liable for, one day's worth of windfall profits, even though the generator's bid was deemed to reflect the exercise of market power.

The events of June 26, 2000 revealed the potential for economic damage from this one-day lag in bid mitigation. On that day, prices spiked to approximately $600/MWh as a result of bids that were subsequently determined to have exceeded the mitigation thresholds. According to the NYISO, consumers bore over $100 million in excess costs

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[32] 92 FERC 61,065 (July 26, 2001).

before bid mitigation could be applied.[33] As a result, and in light of FERC's unwillingness to allow retroactive price corrections, the NYISO subsequently implemented an automated mechanism for mitigating bids prior to setting the market-clearing price. In addition, the NYISO filed for authority to impose penalties and sanctions for repeated anti-competitive behavior.

In March of 2000, the NYISO suspended market-based pricing in the operating-reserve market as a result of evidence of physical withholding and consequent dramatic increase in clearing prices. In compliance with FERC order, the NYISO subsequently restored market-based pricing, but imposed a cap on non-spinning-reserve bids.

In the New York City market, energy prices spiked on a number of high-load days even though a bid-mitigation mechanism was in place for generators that had been divested by ConEd. In response, ConEd proposed, and FERC recently approved, an expansion of the scope of the in-City mitigation mechanism to all generators located within the City.[34]

In summary, all four U.S. ISOs have discovered that their bid-based markets have design flaws that require constant attention ranging from minor adjustments to large-scale overhauls or, in some cases, to complete elimination of the market. Whenever demand approaches the limits of available supply, electricity markets experience price volatility not seen in other markets. FERC has recognized that market based rates may not be just and reasonable under such circumstances.[35] FERC's solution has been to continue the bid caps in PJM and to impose bid caps in the other three ISOs. In fact, the bid caps in NE and NY will remain in effect until the single Northeast market is implemented, at which poitn the continuing need will be reassessed. In an order concerning new bid caps in California, FERC justified the imposition of the bid caps as follows:

> ... as reserves are reduced, all sellers are aware of how tight supplies are relative to the amount they have to offer. Thus sellers have an incentive to offer supply at prices above that which they

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[33] NYISO, "Exigent Circumstances Filing of the New York Independent System Operator, Inc. At the Direction of its Board of Directors to Implement Automated Mitigation Procedure", May 17, 2001, p. 8.

[34] FERC Order on rehearing accepting revised market power mitigation measures, as modified for filing, Consolidated Edison. July 20, 2001.

[35] See, 92 FERC 61,065 (July 26, 2001). In this Order FERC explains why it is imposing bid caps "we believe such a cap is necessary to ensure just and reasonable rates this summer in these markets. We agree with NSTAR that in capacity constrained periods where OP4 conditions apply, the existing New England market does not operate in a manner consistent with a typical competitive market".

See, 97 FERC 61,095 (October 25, 2001). In this Order FERC states: "In our orders approving the previous extension of the bid cap, we noted that if load cannot respond to dramatic increases in prices, then generators can submit very high bids that NYISO must accept when supplies are tight during peak periods, and price spikes can be magnified. We found that these situations can lead to unjust and unreasonable prices if NYISO is forced to accept such high bids and load is not able to reduce its purchases at these prices."

would ordinarily bid. Because of the imbalance of supply and demand, these prices may not be just and reasonable.[36]

3. Assessment of Current Practices

This section presents key aspects of the current market monitoring and mitigation practices of the three northeast ISOs and California. Additional detail is provided in Appendix A. Where relevant, the practices in international markets are mentioned. International practice is discussed in further detail in Appendix B.

3.1 Structure and Budget

In general, market monitoring staff and their budgets have increased significantly each year for the PJM, New England, New York, and CA ISOs. These increases have occurred as a response to the dysfunctions in each of the markets and a growing awareness of the need to monitor, for prospective long-term changes, and mitigate, for immediate correction of short-term problems.

The PJM Market Monitor has had the smallest staff (5). PJM has fewer markets to monitor than the other Northeast ISOs and it does not have the authority to revise prices or mitigate bids.[37] In contrast, New York has the most markets to monitor, the authority to review and revise prices, and the most extensive mitigation process to administer. This is probably why New York, with a current staff of 11 (similar to the staff of ten that New England desires), plans to increase its staff to 23 by the end of this calendar year. New York has acknowledged that its current staff can barely keep up with the "rapid mitigation" thresholds and has spent very little time reviewing the "slow-mitigation" thresholds. New England currently has a staff of 8, with plans to fill two additional positions.[38] New England reviews bids in its energy market and three reserve markets every day prior to accepting bids. New England, which lacks a congestion management system, also has to evaluate all flags for "out-of-merit" generation to determine if individual generator bids should be mitigated.[39]

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[36] 95 FERC 61,148 (June 19, 2001)

[37] Nonetheless, PJM is in the process of expanding its market monitoring staff by two and adding two support staff for a total of nine employees.

[38] In addition, ISO-NE has an internal "price review committee" comprised of ISO-NE employees from market monitoring, markets development, and system operations. This group makes most of the initial decisions regarding the mitigation of bids and the flagging of prices for possible revision later.

[39] This burden has diminished somewhat as reference screens have been developed for many generators to make the bid-mitigation process for out-of-merit generation more mechanical. Also, the NEPOOL Markets

In summary, it appears that as more markets are open to competitive bidding and more extensive mitigation procedures are implemented, market monitoring activities must increase to keep pace.

3.2 Accountability and Independence

The MMUs for PJM, NE, and NY, and the Market Surveillance Unit for CA, are all ultimately accountable to the CEO of their respective ISO and are considered ISO employees. The Market Surveillance Committee, in CA, and the Market Advisors, in NE and NY, are not ISO employees and report to the governing Boards of each ISO. This dual approach appears to be an optimal arrangement for several reasons.

First, having the MMU staffs integrated into the ISO staff structure provides opportunities for informal interactions between the market monitors and the scheduling and dispatch operations at each ISO. As explained by a market monitoring staff person "You can learn much more in a five-minute conversation with a control room operator than you can learn after hours of reviewing print-outs of participant bids and unit commitment reports". This same staff person advocated strongly for "close physical proximity" of market monitoring staff to the scheduling and dispatch functions to allow for frequent and real-time interactions.

Second, having MMU personnel as ISO staff rather than "outside employees" helps lower barriers to communication by allowing all ISO staff to be part of the same team. While some outside observers have concerns that market-monitoring staff will be less vigilant and independent if they are part of the ISO staff, none of the market monitoring staff that we spoke with identified such a concern. It certainly may be appropriate to develop "whistle-blower" protections for ISO market monitoring staff; this would guard against the most egregious forms of management manipulation of market monitoring reports or retaliation for unflattering reports. However, whistle-blower protections are probably needed for all ISO staff, not just market monitoring staff, to ensure the even-handedness, honesty, and independence that are so essential for both market monitors and market administrators.

Third, having an "outside" independent entity reviewing all the market information and reports provides appropriate and useful checks and balances against a dysfunctional MMU (whether due to deliberate concealment or merely incompetent analysis) or an unconcerned ISO management or Board of Directors. Although it appears, to date, that the current ISOs have been quite candid about the problems and failures of their new market systems, it is certainly possible that future managements may become defensive and protective of their market system and be reluctant to identify dysfunctions. An outside independent entity can be very useful if such a scenario develops.

Committee is currently evaluating further changes to MRP 17 to allow for pre-negotiated price agreements for generation units that seldom run in merit, in order to avoid the lengthy after-the-fact settlements.

3.3 Scope of Monitoring and Indices Used

PJM, NE, NY, and CA MMUs are all charged with monitoring all ISO markets and identifying flaws or potential flaws with those markets. Exercises of market power, abuse of rules, and other specific participant behaviors are highlighted. The NY MMU is specifically charged with monitoring the "competitiveness, performance, and economic efficiency" of its markets. The NE MMU is charged with assessing the "competitiveness and efficiency" of its markets and any "aspects that prev
PJM MMU is charged with monitoring "bilateral markets within PJM and regional markets outside of PJM." This last point is worth further discussion. The ability to monitor bilateral contracts, as well as activities outside a particular ISO or RTO boundary, is crucial to understanding the "net" positions of market participants. It may not always be owners of generation resources that can profit from high clearing prices. For example, a load-serving entity that has contracts for resources in excess of its needs will likely be a net-seller in either the day-ahead or real-time market, and, therefore in a position to profit from a high clearing price. In contrast a generator who has contracted to provide more power than its generation units can deliver will likely be a net-buyer in the day-ahead or real-time market, and therefore, in a position to profit from a low clearing price.[40]

Finally, the PJM MMU has the authority to monitor and, with Board approval, intervene in FERC and state proceedings regarding mergers and acquisitions. This is a logical responsibility for an MMU, given its mandate to ensure competitiveness in electricity markets.

The broad scopes of authority granted to MMUs seem appropriate. We did not find any specific enhancements from our review of other MMUs outside the US. However, it is not clear that all the ISOs have been able to structure their activities to meet the broad scope of their general authority. New England and New York have been candid about their inability to implement the comprehensive type of monitoring envisioned in their scopes of authority, in part due to limited staff and resources and in part due to the complexity of developing systems and procedures to do effective monitoring.

Each of the ISOs has developed a variety of indices to use as evaluative tools. Many of them are similar between the ISOs. These include review of concentrations of ownership (HHIs) pool-wide and in specific transmission constrained areas (load pockets); price and cost evaluations using numerous assumptions to simulate a cost-based dispatch; the comparisons of bids and ECPs to fuel-price data; the changes in bid supply curves over time; and changes in generation unit availability as load changes. Appendix C contains even more detailed and specific indices that are used by PJM and CA.

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[40] These are two vastly simplified examples to illustrate a point. In the current markets administered by the ISOs, participants often have numerous "positions"; it is the interaction of all these various positions and the potential for exercises of market power that the ISO MMUs must constantly analyze. Access to bilateral contract within and outside of a particular wholesale market are essential for the MMU staff to see the "whole picture" relative to an individual market participant action.

One evaluative tool that has been particularly beneficial in the UK is the modeling of the dispatch based on marginal cost data provided by the generators. This model is then compared with the bid-based dispatch of the system. While bid-based prices may never actually fall to marginal cost levels, it is extremely useful to compare the differences between the two dispatches as a gauge of the efficiency of the bid-based market. It is also useful to compare the relationship over time (years) as a gauge of overall market competitiveness.

3.4 Data Collection

All FERC approved MMUs have the authority to collect data necessary to perform their market monitoring and evaluation functions. This includes any data collected by their respective ISO and any additional data that the MMU deems necessary. CA requires that data to be collected be published in a "data catalogue" by the ISO and disseminated to market participants.

However, despite this broad authority, none of the ISOs systematically collect marginal cost data from participants on a regular basis. PJM currently collects cost data for generators built prior to July 1996 to support cost capping of bids in local load pockets. New England collects marginal cost data from only those participants who want to negotiate a pre-set bid-price when they are an "out-of-merit" generator due to congestion. New York only collects data from specific generators when requested by the MMU. In California, generators must provide (to CA ISO and FERC) cost data for generation in any month during which the generator submitted a bid that exceeded the proxy price.[41]

Each of the ISOs, except PJM, can penalize participants who fail to provide data upon request. Those penalties can include monetary penalties (CA, NE), restrictions on bids (NE, CA), binding arbitration (NE, NY) and exclusion from the market (CA, NE). PJM is limited to petitioning FERC to enforce its data requests.

3.5 Monitoring Rules and Procedures

The MMUs for PJM, NY, and CA may recommend changes to their market monitoring procedures directly to their governing boards. In addition, NY may recommend changes to its mitigation procedures with the concurrence of the ISO CEO and the Board's Market Performance Committee. The MMU unit in New England can recommend changes after consultation with state regulatory agencies[42] and with NEPOOL approval. All proposed changes would need to be filed and approved by FERC. NE could also invoke its

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[41] 95 FERC 61,115, pp. 15-16. In this order FERC directed that the marginal cost of a generator should be determined using its heat rate, emissions, proxy gas price, proxy emissions cost, and an adder for O&M costs.

[42] This reference to state regulatory agencies is in MRP 17. It is there due to the collaborative process used to develop MRP 17, which involved ISO-NE staff, NEPOOL Participants, state utility regulatory staff, and at least one state attorney general's office.

emergency rule-making authority and implement immediate changes, subject to FERC review; however, to date, NE has never utilized that authority to change market monitoring rules and procedures.

3.6 Market Rules Modifications

The MMUs for PJM, NY, and NE, can make recommendations for changes to the market rules to their respective stakeholder committees. Those committees can then approve the changes, or modify them, and file them with FERC.

In PJM, the MMU also has the authority to file proposed changes directly with FERC, if the changes are approved by the Board of Directors. In NY and NE, the MMU unit can file directly with FERC under each ISO's emergency rule-making authority for exigent circumstances. In CA, the MMU or the independent Market Surveillance Committee can recommend changes to the ISO Governing Board for direct action.[43]

3.7 Corrective Actions

There are a variety of mechanisms that exist within current ISOs for responding to identified competitiveness issues in markets. Some of these tools arise in great part as a result of market flaws that the ISO market-monitoring unit identifies, and some of them are directly within the authority of the ISO to implement.

It is important to note that both the PJM and New England ISO's had more expansive corrective authority during their first year of operations. In PJM, all market participants were required to bid at cost for the first year of operation. In New England, the ISO had the authority in the first five months of operation to revise prices that did not result from competitive forces. In rejecting NE's request to extend that temporary authority in the fall of 1999, FERC stated that the time for such corrections was over; according to FERC, the market participants' need for price certainty outweighed the need to continue to revise prices based on flawed market designs. FERC directed ISO-NE to recommend market design changes on a prospective basis through the NEPOOL committee process, or, if necessary, to make immediate changes using its emergency rule-making authority.

Bid caps

As mentioned earlier, PJM has had a $1,000 per MWh bid cap in place since the start of its markets.[44] CA has had a variety of bid caps in both its reserve and energy markets since the early days of its markets. Most recently, CA had a series of "soft" bid caps ordered by FERC for its energy market in response to the months of high energy clearing

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[43] In CA, as originally constituted, the ISO Governing Board was more similar to a stakeholder committee than an independent Board of Directors. FERC recently changed the composition of the Governing Board to reduce the influence of market participants.

[44] Due to the added cost of congestion, prices may exceed $1,000 per MWh even with a bid cap of $1,000.

prices (and rolling blackouts) that CA experienced in late 2000 and early 2001. The current soft cap in CA for all hours is established in relation to the market clearing marginal cost bid during a reserve deficiency event.[45] NE and NY both have a $1,000 bid cap, that was first approved by FERC in July 2000. Pursuant to recent FERC orders these caps will continue at least until implementation of the Northeast RTO.[46]

In addition to the energy markets, the regulation market in PJM has a $100/MWh price cap; the reserve markets in NE are capped at the energy-clearing price during capacity deficiency events, and the non-spinning reserve market in NY is capped at $2.52/MWh (plus an "opportunity cost" adder).

Bid mitigation

ISO-NE and NY ISO are authorized to mitigate bids prior to accepting them. Until recently, ISO-NE had authority to review any bid and to ask the entity submitting the bid to justify it. NYISO has employed bid screens, or thresholds, for determining which bids are eligible for mitigation since the start of its markets. For automatic mitigation, the threshold is a bid that is 300% or higher than a competitive bid and the impact must raise the clearing price by 200% or more. A second tier threshold allows the NYISO to file a proposed mitigation with FERC if the impact of a bid raises the market-clearing price by 100%. Attempts by market participants to lower such thresholds have been vigorously resisted by the NYISO. In July of 2000, FERC ordered ISO-NE to file mitigation thresholds in order to eliminate the excessive "discretion" that ISO-NE had in deciding which bids to review. In response, ISO-NE developed thresholds that are triggered when a bid exceeds a reference price by 300% or $100, whichever is lower, and the impact on market clearing prices is 200% or $100/MWh, whichever is lower. These are essentially the same thresholds used by NYISO.

If bid mitigation is triggered, bids are reduced to default bids generally set at 100% of a reference price.

In California, FERC has permitted generators to submit bids that exceed the market-clearing price; however, those bids are subject to justification and refund. A generator submitting a higher bid must submit a justification to the ISO and FERC, including a detailed accounting of all of its component costs for each hour where the bid exceeded the market-clearing price. FERC may, upon review of the justification, order a refund.[47]

In the UK, a monitoring group has proposed thresholds that trigger mitigation at significantly lower levels. If a supplier has the ability to raise prices by just 5%,

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[45] 95 FERC 61, 148 (June 19, 2001).

[46] For ISO-NE, see 97 FERC 61,090 (October 25, 2001). For NYISO see 97 FERC 61,095 (October 25, 2001).

[47] 95 FERC 61,115 (April 26, 2001).

mitigation would be applied (the 5% threshold is for a total of thirty days worth of hours over a one-year period). The ability to raise prices by 15% (for a total of 10 days of hours over a one-year period) or by 45% (for a total of about three days of hours over a one-year period) would also trigger mitigation. These thresholds are significantly below the 200-300 % thresholds that NYISO uses, although NYISO is looking at single hour increases and not the cumulative impact over a year.[48]

Price corrections

There are differences in authority for price corrections resulting from errors and those resulting from market-design flaws.

With respect to price corrections resulting from software or data entry errors, it appears that NE, NY, and PJM all have the authority and obligation to correct prices under the filed rate doctrine. As FERC stated:

> ...we believe that it is not necessary to extend NYISO's TEP authority in order to facilitate correction of prices calculated on the basis of computational errors. Under the filed rate doctrine, NYISO already has the authority, and is required, to take corrective actions in a timely manner in order to ensure prices consistent with its Commission-approved tariff.[49]

As a matter of current practice, ISO-NE flags, reviews, and corrects prices within specified time frames. During weekday working hours, prices must be flagged for correction within 75 minutes of being posted and corrections must be made within five days. For all other hours (non-work and weekend), prices must be flagged within 24 hours and revisions made within five days.

With respect to price corrections due to market-design flaws, both NE and NY initially had explicit authority to flag, review, and correct prices. FERC subsequently revoked such authority for both ISOs. PJM has never had authority to correct prices for market-design flaws.

3.8 Sanctions and Penalties

ISO-NE, NYISO, and CAISO have authority to impose sanctions for a variety of participant behaviors. In CA the MMU may recommend fines and suspensions and the ISO Board may impose sanctions. ISO-NE, through specific market rule, may impose sanctions and penalties for physical withholding, failure to perform, failure to follow ISO instructions, inaccurate bid information, and failure to provide requested information. NYISO can impose penalties or sanctions for physical withholding, excess generation,

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[48] See Appendix B for further discussion.

[49] 97 FERC 61,095 (October 25, 2001).

under-scheduling of load, failure to follow ISO dispatch instructions, and failure to provide requested information.

In determining the level of the sanction, ISO-NE uses a series of formulae that increase with each offense. NYISO calculates a market-based penalty for withholding and over-generation. Under-scheduling of load is penalized by a requirement to schedule all load in the day-ahead market, and a penalty factor added to any real-time purchases.

3.9 Congestion Procedures

PJM, ISO-NE, and NYISO have specific monitoring and mitigation procedures for addressing market power related to congestion. PJM and NYISO have congestion management systems that identify locational prices due to congestion. ISO-NE is in the process of developing a congestion management system. For generating units in load pockets, often called out-of-merit generation, all three ISOs impose some form of bid-cap on those generators.

In PJM, generators can choose among three bid caps: incremental cost plus 10%; a reference price based on when the unit was in-merit; or a negotiated price. ISO-NE and NYISO use a reference price for generators who are often in merit. For units that are seldom in-merit, ISO-NE uses a calculated reference price as a staring point for negotiating a price with each generator. ISO-NE has commented that the process of "negotiating" a price with specific generators is a very time-consuming one.

3.10 Reporting Requirements and Data Release

All the MMUs release bid data on a six-month lag. The names of bidders are replaced with identifiers that are supposed to maintain anonymity while allowing bids to be tracked over time. To date, FERC has supported the six-month lag in releasing bid data. The rationale for trying to keep bids anonymous is that competitors will gain an advantage, and be better able to game the market, if the names of bidders are not obscured. Many people have noted that any market participant with a working knowledge of the regional market and generation units can identify individual bidders with a small degree of additional effort. In general it is non-participants, including the public, who are unable to "decipher the code", not market competitors. Consequently, the bid anonymity does little to enhance the competitiveness of the market, and merely makes the markets less transparent to non-market participants.

The six-month lag, too, is intended as a protection against entities trying to game the market. There are some economists, however, who believe that a one-month lag is probably sufficient to prevent anti-competitive behavior. In UK/Wales and Australia markets, bid data is released publicly with only a one-day time lag.

4. Critical issues and recommendations

4.1 Summary

Despite the wide variety of market monitoring approaches that have been developed and implemented by system operators, our research has identified numerous areas of agreement among the market monitors themselves, as well as other market stakeholders, regarding critical structural and functional requirements for effective monitoring, mitigation, and sanctioning of market-participant behavior. This section identifies those areas of agreement. It also looks at some "best practices"[50] that should be adopted for a Northeast RTO, and notes where they are not incorporated into the market monitoring authorities and practices currently in place in PJM. Many of those recommendations could be incorporated in the short-term into PJM's market monitoring practices, pending the development of the Northeast RTO.

In summary, there are four basic themes for effective market monitoring:

1. The market monitor should be independent and charged with a "public interest" responsibility to ensure that markets are workably competitive both in real-time and in the longer-term.

2. The market monitor should monitor and have all the tools necessary to monitor all RTO/ISO markets as well as related energy markets and markets outside the region during all hours.

3. The market monitor should have authority to mitigate, sanction, and penalize, as well as the authority to identify and implement necessary rule changes.

4. The market monitor should encourage transparency in both the marketplace and in its own activities through regular reports.

We will discuss each of these in the following sections.

4.2 Independence and Mandate

The market monitor should be independent and charged with a "public interest" responsibility to ensure that markets are workably competitive both in real-time and in the longer-term.

Recommendation #1: The MMU must closely monitor, and ideally be physically present or adjacent to, the control room dispatch.

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[50] The term "best practices" has become a much-debated term in the context of developing a Northeast RTO. We use the phrase here in a very broad context to refer to existing practices of the Northeast ISO or other ISO/RTO entities that, in our judgment, should be incorporated into market monitoring activities.

Market monitoring requires constant access to and communication with the operators who are setting day-ahead and hour-ahead power schedules as they respond to dynamic system conditions on a seven-day by twenty-four hour basis. For all practical purposes, this close, daily contact with operations staff necessitates the incorporation of the MMU as a department within the ISO.[51]

Recommendation #2: The MMU should report within the RTO to the Board of Directors. The MMU should work closely and collaboratively with the CEO and the RTO staff that has market design responsibilities.

There should be clear and specific procedures to encourage MMU staff to provide current and accurate information on market conditions and behaviors and to protect the staff from any retaliatory actions by management (whistle-blower protection). Of course, the effectiveness of market monitoring, and the potential for addressing identified market competitiveness concerns, will be significantly affected by the institutional arrangements within which the market monitor and its parent organization operate. For example, where market participants have a mechanism for delaying or preventing market rule changes recommended by the market monitor, the effectiveness of the market monitor in ensuring the competitiveness of markets is hampered. On a day-to-day basis, the MMU should function within the RTO as staff and be subject to the direction of the CEO. However, to help ensure the independence of the MMU, its budget and personnel decisions should be under the direct control of the Board of Directors.

Recommendation #3: The RTO should contract with an Independent Market Monitor (IMM) or Market Advisor to complement and advise an internal MMU. The IMM should report directly to the Board of Directors of the RTO.

The IMM, in consultation with the Market Monitoring Unit, should comment on the overall efficiency of the markets and suggest long-term improvements. The day-to-day market monitoring, rules changes, and periodic reporting should reside with the internal RTO MMU. The IMM can also provide a valuable "second opinion" to the RTO Board on market-design issues and proposed rule changes. For that reason, the IMM should report directly to the Board of Directors and stand outside of the RTO organizational structure that reports to the CEO.

4.3 Comprehensive Scope for Monitoring

The market monitor should monitor and have all the tools necessary to monitor all RTO/ISO markets as well as related energy markets and markets outside the region during all hours.

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[51] In the context of a Northeast RTO, it may be appropriate to have satellite MMUs at each control area with a central MMU office at the RTO to coordinate inter-control area monitoring and changes to Northeast RTO market rules and procedures. Even under this scenario, the MMU staff at the control areas may perform best as employees of the same entity that employs the operations staff.

Recommendation # 4: The MMU should be responsible for monitoring all wholesale markets administered or facilitated by the RTO/ISO, including the spot and bilateral energy, ancillary-services, capacity, and transmission markets. The MMU should monitor both supply and load bids in all markets.

Other related markets should be monitored (fuel, emissions, and derivative markets) due to their dynamic interaction with, and impact upon, electricity markets. The MMU should, on a routine basis, collect information on bilateral contracts among participants and monitor electricity options markets as they develop. Monitoring should occur in all hours, and account for different market conditions, including congestion, excess generation, low operating reserves, and system emergencies.

There may be additional markets developed and administered by the RTO (such as a resource-attributes market to facilitate compliance with various state regulatory requirements regarding disclosure, renewable resources, and emissions standards) that will require monitoring and evaluation to ensure competitiveness and efficiency.[52] The MMU should monitor and evaluate all markets based on the opportunities to trade in those markets. Thus, as in PJM today, the MMU would look at both day-ahead and real-time markets. If a four-hour-ahead or hour-ahead market is implemented, this should be monitored also.

Comprehensive market monitoring includes technically challenging and time intensive activities. The MMU must be staffed and budgeted at adequate levels to accomplish all of these functions.

Recommendation #5: As part of its ongoing evaluation of market efficiency and competitiveness, the MMU should evaluate the performance of the markets against the outcome of a market where all bids are at marginal cost.

Bids above marginal cost should be evaluated for their impact on the efficiency of the markets.[53] In evaluating the overall performance of the market, the MMU should compare bids with marginal costs, and determine whether and to what extent actual market prices deviate from competitive outcomes.[54] For this analysis, a model based on

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[52] For example, many of the states in the Northeast RTO require retail load serving entities to provide periodic reports to customers on the fuel-mix of the generation resources purchased for those customers. A few of the states also require minimum percentages of renewable generation resources be purchased for each retail customer. A single regional accounting system for the Northeast market that assigns generation resources to specific load accounts, based on systems already being developed in New York, New England, and PJM, is the simplest and most efficient approach. As New York and New England have already determined, any such system will need to be monitored to ensure that potential gaming and anti-competitive activities are addressed.

[53] Where a distinct ISO capacity market exists, energy supply bids in an efficient market should resemble short run marginal operating costs. In California and other ISOs without a capacity market, energy supply bids may be higher than short run marginal operating costs reflecting recovery of fixed costs.

[54] We are not, however, recommending a specific "standard" for quantitatively determining whether a

marginal-cost bidding is an important analytical tool. While we would not expect actual prices to precisely follow a cost-based model, a cost-based model provides critical information regarding the extent to which actual prices diverge from those would be expected in a truly competitive market with marginal-cost bidding.

Recommendation #6: The MMU should have the authority to assess the impact on the market of proposed mergers and acquisitions, and be a party to such proceedings.

Mergers and acquisitions can have significant impacts on market concentration and the potential for market power to be exercised. The market monitoring plan should provide the MMU explicit authority to participate in merger and acquisition proceedings and provide an assessment of the likely market impacts of the proposed consolidations.

4.4 Authority to Act

The market monitor should have authority to mitigate, sanction, and penalize, as well as the ability to identify necessary rule changes.

Recommendation #7: The MMU should have access to all data that will assist it in performing its market monitoring function.

In addition to all the bids submitted into the market place, the MMU should have access to all operational and systems data collected or generated by other RTO staff and market participants.

The MMU should also have authority to collect marginal cost data and operator logs from market participants. The former data would be used to support the assessment of market performance on the basis of marginal-cost bids, as discussed above. Operation logs would support the MMU's investigation of possible market manipulation through physical withholding.

Recommendation #8: The MMU should have authority to mitigate any bid in any market prior to accepting it.

While thresholds for mitigation may provide useful guidelines for the MMU, they should not limit the MMU's authority to review bids below the thresholds at its discretion. The MMU should have the authority to review bids and take specific appropriate action, subject to appeal to FERC.

Recommendation #9: Bid caps should be used as an essential component of electricity markets.

As FERC has recognized, bid caps have an essential role in securing just and reasonable electricity market prices. In a recent order on California market monitoring, FERC justified the need for bid caps as follows:

> Because of the lack of demand response, these prices may not reflect what the market would have established as appropriate scarcity rents and, therefore, may not be just and reasonable.[55]

Bid caps and bid mitigation should both be used. Although uniform bid caps provide a critical restraint on overall market prices in a small number of high-priced hours, they are not an adequate substitute for generator-specific bid mitigation which addresses potential market power in all hours and under all market conditions. At the same time, bid mitigation procedures, as currently implemented, do not appropriately restrain anti-competitive bidding.

Demand response programs are also not an adequate substitute for bid caps at this time. All current bid-based market structures have difficulty functioning when demand approaches or exceeds available supply, and load response should be developed to address this.[56] However, even under the most optimistic and ambitious scenarios for demand involvement in electricity markets, the point at which demand response will be adequate to restrain anti-competitive supply behavior is at least a decade away.

Recommendation #10: In addition to its authority to mitigate a bid in advance of accepting it, the MMU should also have the authority to impose sanctions or penalties on market participants for specific behaviors, including the failure to provide information requested by the MMU.

The behaviors listed in NEPOOL's MRP 13 are a good initial list;[57] however, the MMU should have the responsibility to identify other anti-competitive or gaming behavior and make them subject to sanctions too. The magnitude of penalties and sanctions should be sufficient to at least offset potential gains from anti-competitive behavior.

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[55] 95 FERC 61,115 (April 26, 2001).

[56] In this regard, RTOs should implement procedures that allow load to bid into the market in the same fashion as generators. For example, market rules could permit load to bid in advance a price at which a specific amount of megawatts could be reduced. Such bids could be treated as generation resource in the daily dispatch bid-stack. Market rules could also allow load to respond, in real-time, to market clearing prices as a price-taker. These approaches should not be limited to large consumers, but should accommodate small loads, including residential loads, that could be aggregated by market brokers. In addition to qualifying for energy market compensation, load responsiveness should also be able to qualify for installed capacity payments and reserve payments to the extent that they qualify. Traditional state and utility sponsored energy efficiency programs should also be able to receive compensation for peak load reductions. As with supply bids, load bids and demand response programs will need to be monitored to ensure that anti-competitive practices can be identified and curtailed.

[57] MRP 13 includes sanctions for following behaviors, if not excused: failure to provide energy, failure to provide services, failure to respond to dispatch instructions, failure to perform in markets, inaccurate bid or operating information, failure to follow scheduling procedures, failure to follow transmission instructions, failure to provide information, and failure to comply with market mitigation rule.

Recommendation #11: The MMU should have the authority to flag clearing prices and make price corrections for a limited period of time after the market clears.

As noted in Section 3.7 above, ISOs have the authority and responsibility to correct prices for errors. However, this authority does not extend to corrections for market-design flaws. Although initially ISO-NE and NY had authority to correct prices for market-design flaws, FERC subsequently revoked it.

The issue of whether to allow price corrections for market design flaws is controversial. In considering whether to allow price corrections for market-design flaws, a key issue is how to balance the market's need for accurate prices with its need for certainty of prices. Ideally, at the end of each day market participants need to know where they stand, i.e., at what price and quantity did they buy or sell electricity. On the other hand, market participants need to have confidence that the systems for establishing prices for sales and purchases produce technically accurate results consistent with a competitive market, i.e., are not subject to manipulation or gaming. Striking an appropriate balance between these competing concerns has been a difficult and on-going challenge for the ISOs and FERC.

We conclude that providing a limited time period for correcting prices for market-design flaws is a reasonable compromise.[58] ISO-NE's 75-minute window during business hours (24 hours for non-business hours and weekends) for flagging a price for review is a reasonable approach.[59] If a price is flagged, market participants are on notice that the price may be revised and can make their forward going decisions accordingly. A five-day period for making revisions after a price is flagged seems to be a reasonable amount of time to complete an initial review. As experienced is gained, the authority to correct prices could be curtailed or eventually eliminated.

Recommendation #12: The MMU should have the authority to file with FERC for changes to both market-monitoring rules and market rules.

There should be a standard process for filing changes (which may include review by stakeholders and the concurrence of the RTO Board). The MMU should also have emergency authority to file changes that go into effect immediately, but are subject to FERC review within 60 days.[60]

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[58] The Pennsylvania Office of Consumer Advocate supports market monitoring authority to make after the fact price corrections for computational errors only. However, the Pa. OCA disagrees that the market monitor should make after the fact price or bid changes to remedy market design flaws or other market abuses. The Pa OCA supports the use of other tools to remedy such flaws and abuses, including filings to change market rules and market design, bid caps, before the fact mitigation of bids, FERC investigations and refunds, sanctions and penalties.

[59] These are the requirements in ISO-NE's MRP 15.

[60] ISO-NE's emergency authority under Section 6.17 of the Interim ISO Agreement is a good model.

Finally, it is critical that the MMU be able to respond to new market behaviors in a dynamic fashion. Market participants are continually striving, as any profit-making entity should, to determine profit-making behaviors that are allowed within established market rules. The MMU must not be overly restricted in its ability to respond to the continuous innovations in market behavior by restrictions on the hours or circumstances under which it can monitor the markets and participant behavior. Competitive electricity markets are still relatively new and are undergoing constant change and evolution. The market monitor cannot be given a static and inflexible tool kit with which to ensure the competitiveness of fluid and evolving markets.

4.5 Data Access and Reporting

The market monitor should encourage transparency in both the marketplace and in its own activities through regular reports.

Recommendation #13: In order to improve transparency and enhance confidence in the markets, the MMU should regularly and frequently issue detailed reports on its monitoring activities.

The MMU, as part of an overall effort, should strive to maximize the transparency of its own actions and the transparency of the markets in general. Absent compelling reasons that specific information will harm the competitiveness and efficiency of the markets, reports on market activities should be posted on the ISO or RTO website. For information that is too sensitive for public release, redacted versions should be provided for posting on the ISO or RTO website. Non-redacted reports, with appropriate confidentiality protection, should be provided to the ISO or RTO Board, FERC, and state jurisdictional entities including state consumer advocate offices.

The type and frequency of reports should be similar to those currently provided pursuant to MRP 17 for the New England wholesale markets.[61] For example, a market monitoring unit should prepare a monthly report that describes activities in each market, compares prices to other markets and previous months, and describes any regulatory actions or rule changes that have occurred. The market monitoring unit should also prepare a quarterly report for regulatory agencies that summarizes the three monthly reports, compares bids and prices to previous quarters, identifies any mitigations and sanctions taken, and an assessment of market efficiency. Finally, the market monitoring units should prepare an annual report that assesses annual market performance against a marginal cost dispatch, assesses the overall competitiveness and efficiency of each market, and describes changes and improvements that were implemented in the reporting year, as well as future refinements to the markets. The annual report should be presented and discussed at an annual forum that is open to the public.

Recommendation #14: Bid data with names should be released on a one-month lag.

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[61] FERC has praised the monthly and quarterly reports produced by ISO New England for their thoroughness, detailed charts, and comparisons to other wholesale markets.

The ISOs currently release bid data on a six-month lag basis and coded to allow tracking of bids without revealing the bidders' names. As a practical matter, coded names are not a barrier to market participants who, with a minimum of effort, can reliably identify the specific bidders. The coded names are an obstacle to non-market participants such as regulatory agencies and the general public who seek to develop a better understanding of participant activities. Therefore, we recommend the release of bid data with the bidders names.

One of the principal reasons to publish bid data is to allow other market participants, regulatory agencies, and the public at large to evaluate the data and comment upon it. Load serving entities, in particular, have a strong interest in uncovering inappropriate bidding activities that raise prices; they are paying those prices to serve their customers. A six-month lag is problematic for two reasons. First, it allows too long a period for gaming activities to go on without detection or correction. Second, it makes detection and correction more difficult due to the long time between an event (such as the $1,000 ECPs in New England this summer) and the opportunity to analyze the bid data that created the event (Summer 2001 data will not be available until January 2002 at the earliest.

There have been proposals to shorten the reporting time from six-months to three-months; a few people have suggested releasing bid data after 24 hours. We are concerned that a 24-hour lag would provide too much detailed information regarding bidding strategies and encourage short-term gaming efforts. However, we believe that the dynamics of the wholesale markets could support a one-month lag of bid data. Bidding strategies are subject to frequent revision based on the changing circumstances of individual participants (for generators this includes outages and other variations to their generating capacity; for load serving entities this includes changes to their customer base) and the market in general (the combined effect of thousands of individual participant factors). Such a dynamic process is likely to diminish the value of one-month old bid information to those entities that would try to manipulate the market based on such information.

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Appendix A
Comparison Tables:
Market Monitoring in PJM, New York, New England, and California

Table A4: Data Collection

	PJM	NY	New England	CAL ISO
Authority	MMU has access to all data gathered or generated by ISO during course of normal business operations (MMP VI.A). MMU also authorized to request additional data from market participants (MMP VI.B).	MMU has access to all data gathered or generated by ISO during course of normal business operations (MMP 6.1). MMU also authorized to request additional data from market participants (MMP 6.2).	MMMG has access to any and all data that ISO-NE deems necessary, including cost data from generators (MRP 17.6.1).	MSU develop and refine catalog of data to collect, and procedures to handle data (MMIP 4.1.2). MSC full discretion to specify data types and evaluation criteria (MMIP 6.1). ISO CEO must institute data collection, organization and analytic activities to support MSU (MMIP 3.3.3.2). Data catalog published and disseminated to Participants (MMIP 8.1).
Generator cost data collected	Systematically for all generators on-line prior to July, 1996 (OA, Schedule 1, 6.4; OA, Schedule 2).	No systematic collection. MMU may request specific data from individual generators (MMP, 6.2.1).	Only for generators that seek to negotiate a bid-price with ISO-NE due to congestion.	Generators who submit a bid that exceeds that market-clearing price must submit cost data to ISO and FERC (95 FERC 61,115, p. 15-6).
Enforcement ability	No direct enforcement authority. MMU can petition FERC to	Market participants required to promptly provide data requested	Interim ISO Agreement states that NEPOOL Participants "shall	ISO may impose penalties or sanctions for ISO Participant's failure

	enforce requests. (EDR, at 10).	by MMU, and to submit to binding arbitration in the event that MMU determines that the requested data will not be provided within a reasonable time (MMP 6.2.2).	provide the ISO with any and all information . . . that the ISO deems necessary" (IIA 7.2). Also, MRP 13 provides sanctions for failure to respond to data requests.	to provide information, including exclusion from market (MMIP 4.5.2). MSU may report failure of other entities (e.g. PX) to ISO CEO and Governing Board or to pertinent regulatory agency (MMIP 4.5.1).
Requests for data collected by Market Monitoring entity	No provision.	Upon request, MMU may publicly release data if such data is not confidential and release of such data would not be overly burdensome (MMP 6.4(e)).	Data may be released subject to the confidentiality limitations of the NEPOOL Information Policy (MRP 17.6.1).	ISO CEO has sole discretion whether to provide data it has collected to Participant who requests it (MMIP 4.5.3).

Table A5: Changing Market Monitoring Rules

	PJM	NY	New England	CAL ISO
Authority to change market monitoring rules	MMU may recommend to the PJM Board changes in the MMU or MMP (MMP VII.A)	Market Advisor and MMU may recommend changes to the MMU or MMP as part of its annual report to the Board (MMP 10.1). In addition, Market Advisor and MMU, with approval from CEO and Board's Market Performance Committee, authorized to recommend revisions to existing mitigation measures (MMP 8.2)	MMMG can propose changes to monitoring and mitigation rules for filing with FERC, in consultation with regulatory agencies and NEPOOL, or by ISO-NE in emergencies (MRP 17.1.3 and 17.5)	MSU may recommend to the ISO Governing Board changes to its rules and protocols (MMIP 2.3.2)

Table A6: Changing Market Rules

	PJM	NY	New England	CAL ISO
Market monitor authority to market rules	MMU may recommend changes to stakeholder committees or, with Board approval, file for changes directly with FERC (MMP IV.A)	MMU may recommend changes to stakeholder committees, CEO, or Board (MMP, 11.1(d)). Board may file for changes without committee concurrence only to address exigent circumstances. (ISO Agreement, Article 19)	MMMG reports to VP of Markets Development who can propose market rules changes for NEPOOL consideration, or on its own subject to 6.17 of the IIA (IIA 6.4 and MRP 17)	MSU may recommend changes to rules and protocols of PX, ISO markets, PX markets (MMIP 2.3.2)

Table A7: Bids Caps, Bid Mitigation and Market Price Changes

	PJM	NY	New England	CAL ISO
Bid caps	$1,000/MWh cap on energy bids (OA, Sched 1, 1.10.1A). $100/MWh cap on regulation bids (OA, Sched 1, 1.10.1A). During first year of markets, all generators required to bid at cost.	$1,000/MWh cap on energy bids (Services Tariff, Attachment F). $2.52/MWh plus opportunity cost on bids for non-spinning reserve (FERC order, 11/8/00.)	$1,000/MWh cap on energy bids; reserve prices not to exceed energy price (FERC Order, 10/25/01)	FERC has instituted a soft bid caps, based on proxy marginal costs, for periods of capacity shortage as well as non-shortage hours (95 FERC 61,115,s issues April 26, 2001 and 95 FERC 61,418, June 19, 2001)
Bid-mitigation authority	None, other than in local load pockets.	MMU authorized to mitigate supply bids in day-ahead and real-time energy and reserve markets (MST, Attachment H, Section 4).	MMMG authorized to mitigate Participants' bids and unit characteristics subject to specific thresholds (MRP 17.2).	NA
Bid-mitigation practices	NA	Bid-mitigation triggered only when suspect bid exceeds reference level by threshold amount and only if bid-mitigation would reduce LBMP by threshold amount (MST, Attachment H, 3.1-3.2).	Thresholds for bid-mitigation are specified in reference price screens (17.2.2.1), investigation thresholds (17.2.2.2), and Hourly Market Impact and Uplift Thresholds	NA

		In addition, MMU can file with FERC for mitigation authority in the event that bid has material effect on market prices, but does not exceed standard mitigation thresholds. (MST, Attachment H, 3.2.3).	(17.2.3).	
Corrective actions	MMU authorized to issue demand letters to market participants to cease actions found to be in violation of rules, standards, or procedures (MMP IV.A).	If bid triggers mitigation, MMU authorized to substitute "default bid" based on previous unmitigated bids (OA, Attachment H, 4.2). For day-ahead market, default bid substituted prior to setting, and used to set, LBMP. Default bid applies for six months. (MST, Attachment H, 4.6) In addition, MMU authorized to engage in discussions with, or issue demand letters to, market participants to	MMMG may substitute a default bid that is 100% of the Reference price determined through 17.2.2.1 (17.2.4).	FERC may order refunds upon reviewing justification of bids that exceed the market-clearing price (95 FERC 61,115; 95 FERC 61,418).

		correct actions found to be in violation of rules, standards, or procedures. (MMP, 11.1).		
Authority to Change Market Prices	Can revise prices due to computational errors.	Can revise prices due to computational errors.	Limited ability to change market prices based on human or software error, or due to extreme system emergency (MRP 15) MRP 15 allowed revisions for prices that did not result from a competitive market for first 90 days of new markets. Extended for 60 days; additional extension denied by FERC.	
Practices for Changing Market Prices	NA	NA	Prices must be flagged within 75 minutes to 24 hours and corrections must be made within five days (MRP 15).	

Table A8: Sanctions

	PJM	NY	ISO NE	CAL ISO
Authority	No direct authority.	Authorized to impose penalties or sanctions for occurrences of physical withholding, generation in excess of dispatch signal, or under-scheduling load in day-ahead market (MST, Attachment H, 4.3, 4.4).	Authorized to impose sanctions for a variety of behaviors including physical withholding, failure to perform or follow ISO instructions, inaccurate bid information, and failure to provide information (MRP 13 & 13A).	MSU may recommend actions, including fines and suspensions, against specific entities (MMIP 2.3.2) ISO Governing Board, acting upon recommendation of MSU or MSC, and after audit by MSU, may impose sanctions within its authority, or may recommend sanctions to regulatory agency (MMIP 7.3).
Practices	NA	For physical withholding or over-generation, penalty set at product of amount withheld (or over-generation) and real-time LBMP (MST, Attachment H, 4.3). For load under-scheduling, requirement	Administrative and formula based sanctions for specific behaviors (MRP 13A).	

		to schedule all expected load in day-ahead market, and penalty for purchasing in real-time market in excess of specified allowance level (MST, Attachment H, 4.4).		
Market Participant Recourse			Participant may seek ADR review of any sanctions. Decision from ADR process may be appealed to FERC by participant or ISO-NE. MRP 13.	MSU may institute ADR to resolve differences with market participants over interpretation of behavior and appropriate remedies. (MMIP 2.3.3)

Table A9: Congestion and Load Pockets

	PJM	NY	New England	CAL ISO
Authority	Authority to cap bids of units within load pocket required to be dispatched out of merit for reliability purposes (OA, Sched 1, 6.1). Exception for units relied on to relieve Western, Eastern, Central reactive limits, or other constraints exempted by FERC (OA, Sched 1, 6.4.1(d)).	Authority to cap: 1. Energy bids of units within NYC load pocket whenever (1) transmission constraints limit imports of generation into NYC; or (2) units required to be committed or run out of merit for local reliability purposes. (ConEd Rate Schedule No. 199, Section B [As modified pursuant to 7/20/01 FERC order]). 2. Bids into, and prices received from, NYC installed capacity market (ConEd Rate Schedule No. 199,	Authority to cap bid prices at a reference price for generators in congested areas (defined as less than three competitors). Authority to cap bid prices at a predetermined level (based on cost data) for generation units that are seldom selected, except due to congestion.	

		Section C). 3. Spinning-reserve bids for units committed to meet local spinning-reserve requirements (ConEd Rate Schedule No. 199, Section D).		
Eligibility	All generating units built prior to July, 1996 subject to mitigation. (OA, Sched 1, 6.1)	All generating units located within NYC subject to energy bid cap. ICAP and spinning-reserve caps applicable only to generating units divested by ConEd (ConEd Rate Schedule No. 199, Section A).	Generation units selected as out-of-merit generators.	
Markets subject to mitigation	Restricted to day-ahead energy market (OA, Sched 1, 6.4.1). PJM recently requested authority to apply on real-time basis (6/29/01 filing letter).	Applicable to day-ahead and real-time energy markets, installed capacity market, and spinning-reserve market (ConEd Rate Schedule No. 199).	All markets.	
Bid cap	As elected by generator, bid mitigated to either	In day-ahead energy market, bids mitigated to	Mitigated to reference price (formula based) for	

	(1) incremental cost + 10%; (2) average of LMP at generator bus during hours when unit dispatched in merit order; or (3) amount negotiated with generator (OA, Sched 1, 6.4.2)	"reference price" based on previous unmitigated bids. In real-time energy market, bids set at 10% above reference price. (ConEd Rate Schedule No. 199, Sections B.1, B.2). In installed-capacity market, divested generators' bids and prices received capped at $105/kW-yr (ConEd Rate Schedule No. 199, Section C). In addition, divested generators required to bid all capacity into NYC installed-capacity auction. In spinning-reserve market, divested generators' spinning-reserve availability bids capped at $0 (ConEd Rate Schedule No. 199, Section D).	generators who are often selected in-merit. For generators seldom selected in-merit, a reference price or a negotiated price is used New rules regarding "net commitment period costs", or npcp, provide a method for calculating uplift payments.	

Table A10: Data Reporting and Release

	PJM	NY	New England	CAL ISO
Reporting within ISO	MMU provides periodic reports to the PJM Board (MMP VII.A).	Market advisor and MMU provides reports to the Board on an annual basis (MMP, 10.1) Reports also provided periodically upon request of Board, CEO, FERC, or NY PSC (MMP, 10.2)	Monthly reports to CEO and Board (internal).	MSU must report to ISO CEO and MSC not less than quarterly, and to ISO Board not less than annually, and as needed (MMIP 4.4.1) Director of Department of Market Analysis reports to Governing Board monthly (website) MSU may report directly to MSC (MMIP 4.4.3) MSC must report on its evaluations and recommendations to ISO CEO and Governing Board (MMIP 6.3.1) MSC may require ISO CEO to publish or include MSC reports/findings (MMIP6.4).

Reporting to FERC	MMU provides FERC with all reports to the PJM Board, or any other report requested by FERC (MMP VII.B)	MMU provides FERC with all reports to the Board, or any other report requested by FERC.	All reports to FERC.	MSU reports to FERC annually, reports approved by ISO CEO (MMIP 8.3) MSC may report to FERC (MMIP 6.3.1) Recently FERC has required weekly reports of schedule, outage, and bid data, with identification of bidding behavior issues (95 FERC 61,115, p. 18).

Appendix B
International Approaches to Competitive Markets

England and Wales[62]

The electricity industry was first privatized in 1990 and the Electricity Pool was set up. It was operated under a commercial arrangement: the Pooling and Settlement Agreement, between the generators and the retailers. The pool "was used to determine which generating assets were called on to satisfy demand. The wholesale electricity price was set on a half-hour basis by the most expensive generator used during that period, with all generators receiving that 'marginal' price."[63] There were only two major generators (National Power, now Innogy, and Powergen) at that point, creating a strong potential for the exercise of market power. The main response of the regulator was to force plant sales and divesture. The government also imposed a cap on the pool price.

A new system was set up this year, the New Electricity Trading Arrangements (NETA). It encourages a move towards bilateral contracts signed between generators and retailers and large customers. In addition, five power exchanges have been set up or are in the process of being created. The UK Power Exchange (UKPX) spot market, which started on March 25, 2001, is a 24-hour seven-day market. The owner and operator of the transmission system, National Grid Co. (NGC), a publicly-traded company, "accepts offers and bids from 3 ½ hours ahead of real time, up to real time".[64] This balance and settlement mechanism is managed by Elexon, a non-profit, uncontrolled subsidiary of NGC.[65] This new system seems to have led to a reduction in prices: according to an OFGEM news release in August 2001, "wholesale electricity prices are 20-25 per cent below prices that would have been produced under the Pool" (i.e. the previous system).[66]

The main regulatory agency is Ofgem, the Office of the Gas and Electricity Markets.[67] Ofgem was formed in early 1999, combining formerly separated gas and electricity activities. In terms of market monitoring, Ofgem is charged with overseeing competition of licensees (the market participants) and to refer anti-competitive practices to UK's Competition Commission. Ofgem's Director General (the Director Generator of

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[62] Scotland has a similar framework but there are only two vertically integrated electricity companies. Northern Ireland does not yet have an open market. IEA (2001).

[63] Levesque (2001).

[64] Levesque (2001).

[65] www.elexon.co.uk

[66] "Reviews address NETA's performance and its impact on smaller generators", OFGEM News Release, August 31, 2001 (PN 38). Available at http://www.ofgem.gov.uk.

[67] See www.ofgem.gov.uk

Electricity Supply, DGES) is appointed for 5 years and this mandate can be renewed once. As of March 1997, Ofgem had 233 staff and its running costs for the fiscal year finishing March 1997 were 13 million pounds (UK).[68]

Bower points out, quoting a 1998 report by the electricity regulator, that "[i]n the England and Wales market, strategic capacity withdrawal, especially of marginal plant, has been a major regulatory problem and Ofgem has over the years launched a number of investigations into this kind of behavior by the largest fossil fuel generators PowerGen and National Power".[69] Ofgem has also recently ordered that firms wishing to close plants have to demonstrate that it was uneconomic to operate the latter at the existing market prices. This requirement is likely to lead to spare capacity being put up for sale to competitors.

UK's Competition Commission is the current public independent body, created in 1998, dealing with mergers, abuse of dominant position and other anti-competitive behaviors.[70] Ofgem has been in disagreement with the Competition Commission on the extent of its market monitoring capacity. The Ofgem intended to introduce a so-called Market Abuse Condition in the licenses of generators "capable of exercising substantial market

[71] Two generators (out of eight major ones that had been identified) refused the inclusion of the Market Abuse Condition in their license and were referred by Ofgem to the Competition Commission. The Commission found in favor of the two generators and Ofgem had to withdraw the Condition from all the operating licenses where it had been included.

It is worth giving some details on this condition, since Ofgem still pushes for it: Ofgem "has managed to get the Department of Trade and Industry to look at its case again, with a view to getting the [condition] reinstated under the 'Secretary of State's special Neta Power', provided by the Utilities Act".[72]

The term substantial market power was defined in the initial Ofgem guideline as "the ability to bring about, independently of any changes in market demand, a substantial change in wholesale electricity prices".[73] The Competition Commission warned that "[M]ore than one license-holder or interconnected group of license-holders may simultaneously have, and exercize, substantial market power in the Pool".[74] The

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[68] IEA (2001).

[69] Bower et al. (2001), p. 1004.

[70] See UK's competition web site at http://www.competition-commission.org.uk/

[71] UK's Competition Commission (2001), p. 88. This reference is not yet included in the list of References.

[72] "Return of the MALC", http://www.energy-directory.com, August 2001.

[73] *The market abuse licence condition for generators. A decision document.* OFGEM, April 2000.

[74] UK's Competition Commission, 2001, p. 89.

precision with which the criteria for potential market power were defined is interesting. The Ofgem guidelines stated that market power could occur through very large effects on prices which occur over a short period of time, or through a series of lesser effects on prices that occur over a longer period of time. The document stated that a license-holder had the ability to exercise substantial changes in wholesale prices if it has the ability to bring about a change of:

(i) 5 % or more for a duration of more than 30 days in a one-year period;

(ii) 15 % over ten days in a one-year period, or

(iii) 45 % over 160 half-hours (a little less than 1 % of the year) in a one-year period.

These do not have to be considered continuous periods.

The DGES would have a duty to take enforcement action (except in certain specified circumstances when the Competition Act would be the most appropriate way to proceed).[75] Ofgem could ask further information from the generators to come up with its initial findings and provisional orders. After a period for comments by the license-holder at each stage of the investigation, Ofgem would be entitled to issue an order. The penalties could amount up to 10 % of the license-holder's turnover. An Advisory Board of five members would be formed to advise on Market Abuse Conditions matters. If the DGES disregarded the opinion of the Advisory Board, the enforcement order may be subject to a legal challenge – thus ensuring a way of appeal.

It will be worth analyzing how much of these provisions might disappear in the new version of the Market Abuse Condition.

Nord Pool **(Norway, Sweden, Finland and Denmark)**

The Nordic Power Exchange, or Nord Pool, is "the world's only multinational exchange for trading electric power".[76] It was created in 1993, initially in Norway, and is owned by the two national grid companies, Stattnett SF in Norway and Affärsverket Svenska Krafnät in Sweden. Since 1990, the four Nordic nations (Norway, Sweden, Finland and Denmark) operate in a joint, competitive wholesale market. This is only a power exchange market and the two grids remain owned by the national companies. There is regulated third-party access to the consumers and all consumers may choose their suppliers (except in Denmark, where consumer choice is planned to begin in 2003). Transmission is owned in each country by an independent, usually publicly-owned company (in Finland, there are some private stakeholders in it); there is accounting unbundling of distribution from generation and electricity sales.[77]

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[75] UK's Competition Commission, 2001, p. 91.

[76] www.nordpool.com

[77] IEA (2001).

Most market monitoring was at the national level until recently. However, with the increasing share of electricity traded across borders, the market surveillance of Nord Pool has been reinforced. At the end of 2000, Nord Pool decided to strengthen the monitoring of its physical and financial markets by creating an independent dedicated department. Some of the features of market monitoring include:

- An obligation for Nord Pool participants to "disclose market sensitive information".[78] This type of information (for example about incidents related to the power system, maintenance) is provided first to Nord Pool. The rules are in the process of being defined.

- Flagging bilateral-market agreements. This is a proposal by Norway's parliament: all bilateral market trade in standardized financial power contracts within imposed deadlines would have to be notified.

- Nord Pool tries to obtain full "authority to investigate situations to determine whether there has been undue exercise of market power or insider trading".

- Nord Pool is also considering the creation of an ethics council entitled to make statements and recommendations, but not to impose sanctions.

Australia

The restructuring of the electricity market was initiated in 1995 with the adoption of a comprehensive plan to create a competitive National Electricity Market (NEM). This wholesale market includes, as of the Summer of 2001, five Australian States and territories and was launched on December 13, 1998. One of the distinctive features of the Australian model is that the Australian Competition and Consumer Commission (ACCC) is both the national electricity regulator and the competition authority.[79] Furthermore, the ACCC also covers gas, telecommunications and airports. The states and the central Commonwealth government cooperate through the Council of Australian governments. States have a rather wide responsibility in protecting competition and consumers.

The ACCC investigates market arrangements and behavior that may contravene antitrust laws. Tracking misuse of market power is also one of its roles, according to the Trade Practices Act 1974. The Commission is composed of seven members, appointed by the federal government after consultation with the states. Their five-year term is irrevocable and they can be re-appointed. The ACCC is financed through the Treasury's budget, with a small amount coming from authorization fees and fines. The state regulation authorities also monitor market conduct of retailers and distributors.[80]

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[78] www.nordpool.com

[79] www.accc.gov.au

[80] IEA (2001).

One of the characteristics of the Australian market surveillance system is the very short lag (one day) in releasing bid data in the wholesale electricity market. Anyone can consult this information at the following link:
http://www.nemweb.com.au:9080/REPORTS/CURRENT/YESTERDAYS_BIDS_REPORTS/[81]

The ACCC cooperates with the National Electricity Code Administrator (NECA) to ensure the "effectiveness, efficiency and equity of the national electricity market".[82] NECA has a market surveillance program through which "variations between forecast spot prices and actual spot prices" are analyzed. According to the National Electricity Code (Clause 3.13.7), the ACCC predetermines the acceptable thresholds for this gap between forecast and reality. NECA "will report incidents where it finds that significant variations are caused by activities that in its opinion are inconsistent with the objectives of the market" and notify the ACCC. NECA also performs routine monitoring of market participants.[83]

NECA is also entitled to establish reporting requirements from the market participants. NECA can thus obtain data on registration, prudence requirements, market operations, rebidding, and settlements. NECA provides, among other publications, annual public market reports.

Germany

Germany was perceived as a success story of electricity restructuring for consumers when its electricity market was liberalized in April 1998 (following the 1997 EU Electricity Market Directive). It ended 100 years of local monopoly supply and combined a negotiated third-party access model with an optional single buyer approach for small municipalities (to preserve cross-subsidization of other public services). Average industry tariffs dropped by 27 % between April 1998 and the end of 1999.[84]

The main reason for this drop in prices was an intense price war from the incumbents. This predatory pricing strategy of matching or undercutting best prices was intended to preserve market shares and prevent new competition. The downward trend in prices created a benign regulatory attitude towards mergers. Also, before January 1999, energy was not

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[81] Note that similar data is available for the English and Wales' market at http://www.esis.co.uk/market/registration.html

[82] From NECA's web site, at www.neca.com.au

[83] A memorandum of understanding between the ACCC and NECA can be found on the NECA web site (http://www.neca.com.au). The guidelines for NECA investigation can be found at http://www.neca.com.au/SubCategory.asp?SubCategoryID=179

[84] Bower et al. (2001).

covered by the German anti-trust law and monopolies were, thus, tolerated.[85]

However, this first competitive environment may be altered in the coming years, as underlined by Bower et al. (2001) in an article in *Electricity Policy*. There has been a large movement of concentration in the German market, starting in September 1999 when VEBA and VIAG, two German conglomerates with electricity subsidiaries, announced their intention to proceed with the largest merger in German history.

The VEBA/VIAG merger and another major merger between RWE and VEW were authorized in early 2000, but the European Commission insisted that this authorization was conditioned on divestment of shares in commonly-owned generators, scrapping of the transmission tariffs between North and South Germany and agreement to sell or auction cross-border transmission capacity where there appeared to be constraints (Bower et al., page 990).

Germany refused to create an Independent System Operator. The regulation of grid access and transmission pricing was negotiated directly by associations in the electricity industry and heavy industry. The first associations' agreement, reached in May 1998, was modified in January 2000, after some problems with high transmission prices and denial of access occurred. There is no dedicated electricity regulatory body and the German Cartel office deals with concentration issues. The EU anti-trust authority also has authority.

There is thus a continuing potential for the exercise of market power in Germany. Although the market has been rather atomistic in the past, it no longer is. The electricity companies were also vertically integrated up to now, but this may change, too. Thus, although Germany may be considered by some as a platform for an EU-wide model, it does not appear to be equipped with sufficient regulatory tools to monitor market power in the future.

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[85] This illustrates, more broadly, a higher tolerance for concentration in the German economic environment and regulation. This contrasts with more aggressive anti-trust attitude in Anglo-Saxon countries.

Appendix C
Market Monitoring Indices of California and PJM

For PJM (from the PJM MMU Report to the FERC: *Assessment of Standards, Indices and Criteria*, April 1, 2001).

1. Summary statistics for PJM system by hour/day/week/month/year.
    a. PJM system prices and loads: day ahead and real time markets.
        i. Average PJM load weighted price;
        ii. Maximum PJM load weighted price;
        iii. Average PJM load;
        iv. Maximum PJM load;
        v. Correlations between PJM prices and loads.
    b. PJM congestion.
        i. Maximum hourly congestion costs;
        ii. Total congestion cost;
        iii. Number of active constraints.
    c. PJM volumes.
        i. Total MW bid;
        ii. Total MW self scheduled;
        iii. Total bilateral contract MW;
        iv. Hourly net imports and exports including all components.
2. Day ahead market
    a. Total hourly load
    b. Composition of load
        i. Fixed price bids
        ii. Price sensitive bids
        iii. Decrement bids
    c. Composition of supply offers

i. Generation offers

ii. Increment offers.

3. Aggregate relationships between day ahead and real time markets

   a. Hourly aggregate LMP comparisons

   b. Hourly aggregate load comparisons

   c. Hourly aggregate congestion comparisons

4. Comparative prices and loads for PJM and surrounding power markets:

   a. Forward prices for each system by market term;

   b. Forward price spreads by market term;

   c. Real time prices as available;

   d. Real time price spreads;

   e. Loads for each system as available;

   f. Net imports/exports between PJM and each system.

5. Locational prices and loads.

   a. Bus locational marginal prices (LMPs);

   b. Aggregate LMPs;

   c. Bus LMPs less the PJM average price;

   d. Loads and generation by bus;

   e. The distribution of LMP rankings for each bus by bus price and by bus load/generation;

   f. Daily/weekly/monthly price-load comparisons:

      i. Maximum bus LMP by hour;

      ii. Minimum bus LMP by hour;

      iii. Average load LMP by zone, by aggregate load bus, for PJM;

      iv. Average generation LMP by zone, by aggregate load bus, for PJM;

      v. Load/injections by bus, by zone, by aggregate buses, for PJM.

g. Zonal LMPs

   i. Zonal daily LMP

   ii. Highest bus LMP within zone;

   iii. LMP ranking across zones.

6. Congestion by hour/day/week/month/year by bus/zone/bus aggregates.

   a. Total congestion costs for period;

   b. Peak congestion costs;

   c. Percent of time with congestion;

   d. Frequency of individual constraints;

   e. Frequency of must run price cap implementation;

   f. Frequency of constraints without must run price cap implementation.

7. Transmission congestion and FTR revenue adequacy.

8. Congestion comparisons between day ahead and real time markets

   a. Total congestion costs for period;

   b. Peak congestion costs;

   c. Percent of time with congestion;

   d. Frequency of individual constraints;

   e. Frequency of must run price cap implementation;

   f. Frequency of constraints without must run price cap implementation.

9. Offers and dispatch.

   a. Unit offer/supply curves;

   b. Maximum economic offer;

   c. Minimum economic offer;

   d. Company aggregate offer/supply curves;

   e. Aggregate PJM supply curves;

f. Comparisons of unit offer/supply curves to historical offer curves;

g. Comparisons of company offer/supply curves to historical supply curves;

h. Comparisons of aggregate PJM supply curves to historical supply curves;

i. Deviations from requested dispatch, by unit;

j. Ramp rates by unit, by time period, by company.

k. Comparisons of ramp rates by unit type, by company.

l. Operational constraints on offers: start times; minimum run requirements; minimum down times; maximum starts.

m. Start up costs.

10. Comparisons between day ahead and real time offers

11. Relationship between offers and LMPs

    a. Identification of units which set price;

    b. Identification of fuel type of marginal units;

    c. Frequency of individual units setting price;

    d. Frequency of generation owners setting price.

12. Transmission contracts.

    a. Contract quantities;

    b. Service types;

    c. Contract paths.

13. Energy contracts.

    a. Contract quantities;

    b. Service types;

    c. Contract paths.

14. Regulation

    a. Available regulation

    b. Regulation offers

c. Regulation price

d. Aggregate regulation supply

e. Regulation adequacy

15. Spinning.

a. Condenser bids;

b. Condenser costs;

c. Condenser credits;

d. Total condenser MWs;

e. Total spinning requirements.

16. FTR Auction Market.

a. Total market volume offered and cleared;

b. Total market revenue;

c. Average clearing price;

d. Path specific revenue and volume;

e. Source specific revenue and volume;

f. Sink specific revenue and volume.

17. Available capacity

a. Total capacity resources;

b. Total available capacity;

c. Outage status by unit;

d. Frequency of outages, by type, by unit, by time period;

e. Comparisons of outages across units;

f. Company summary outage frequency;

g. Comparisons of outages across companies;

h. Frequency of unit outages by time period, by demand conditions; by system/bus price.

18. Capacity market

    a. Company supply curves by time period of market;

    b. Company demand curves by time period of market;

    c. Supply/demand balance;

    d. Market prices for each market;

    e. Comparisons of offers to opportunity costs;

    f. Delisting of units by company;

    g. Capacity position by company.

19. Market structure by market

    a. Concentration ratios by hour;

    b. Incremental concentration ratios by hour;

    c. Concentration ratios by transmission defined markets within PJM;

    d. Concentration ratios by zone;

    e. Concentration ratios by interface.

20. Price-cost margins

    a. Unit specific price-cost margins;

        i. Compare unit offers to unit costs

    b. Company price-cost margins;

        i. Compare unit price-cost margins by company.

    c. Price-cost margins for marginal units

    d. Aggregate price-cost margins

For comparison, from the California ISO web site (*ISO Market Monitoring and Information Protocol*, Appendix 2)

Data derived from sources partly or wholly external to the markets administered by the ISO and PX

A. Market Clearing Price Indices

1. The percentage of Settlement Periods in which a Market Participant has set, or has submitted bids close to, the Market Clearing Price in the Energy and Ancillary Service markets overall, and in relation to the following time periods or market conditions:

    a. when such Market Participant is:

        i. a net buyer of Energy and Ancillary Services,

        ii. a net seller of Energy and Ancillary Services;

    b. during on-peak hours and off-peak hours;

    c. in different time periods otherwise of relevance to the state of the markets;

    For each of these situations, bids submitted when Congestion is present and those when there is no Congestion will be compared. These indices will also be examined in relationship to other "vulnerable periods" and bidding strategies;

2. the relationships between the Market Clearing Prices in the various markets administered by the ISO and PX, e.g., between the Imbalance Energy market and the Energy and Ancillary Services markets;

3. the record of Market Participants setting Market Clearing Prices in the context of the inter-market relationships as described in (2);

4. The percentage of Settlement Periods in which a Market Participant has set, or has submitted bids close to, the Market Clearing Price when such price falls into a particular segments of the market price curve, e.g., $20-30/MWh, and $30/MWh and above;

5. A "price mark-up" check that measures the differences in Market Clearing Prices between unconstrained periods and constrained periods.

B. Comparison and Evaluation of Specific Bidding Strategies of Market Participants

1. Correlation between bidding behavior of Market Participants and

their establishing the Market Clearing Price at times when they are:

i. net buyers of Energy and Ancillary Services,

ii. net sellers of Energy and Ancillary Services;

2. bidding and rebidding strategies of Market Participants, especially those that frequently set Market Clearing Prices during iterations in the bidding cycles of each market, both within and between the markets administered by the ISO and PX;

3. comparison of bidding strategies for the same Generation Unit into Day-Ahead Market, Hour-Ahead Market and Imbalance Energy markets;

4. comparison of bidding strategies for the same Generation unit into the Energy, Ancillary Service and Imbalance Energy markets;

5. comparison of Supply Bids of Generation units with similar technology/age characteristics;

6. Supply Bid and Generation Unit withdrawals and redeclarations during bidding cycles;

7. correlation of changes to initial Supply Bids with Market Clearing Prices, e.g., to ascertain if redeclarations cause or lead to increases in such prices;

8. comparison of bidding strategies for the same Generation Unit in relation to the following time periods or market conditions:

. when the Market Participant that owns the unit is a net seller or a net buyer of Energy or Ancillary Services;

a. when congestion is or is not present;

b. when a Reliability Must-Run Unit is called or not called;

c. when "near Congestion" occurs. "Near Congestion" means the final scheduled power flow over an Inter-Zonal Interface is within a few percentage points of the Available Transmission Capacity, or when congestion would occur with the initial Preferred Schedules but is alleviated after rebidding;

9. comparison of bidding strategies of Market Participants in relation to their market share;

10. relationships or correlations between the ability of Market Participants to set Market Clearing Prices or certain type of bidding behavior and periods or circumstances in which such Market Participants may have exclusive or restrictive access to data, e.g., as to costs or availability of Reliability Must-Run Units, or as to expected or actual outages of Generation Units or transmission

facilities;

C. Indices of Market Concentration

The ISO Department of Market Analysis will use dynamic, geographic and product market specific indices based on actual market operation data as indicators of the competitive condition of the ISO and PX markets. The planned indicators are:

1. Market share for the largest supplier.

2. Measure of supply responsiveness. This is a measure of how much additional power would be supplied for a given increase in price.

3. Traditional measures of concentration which might include conventional HHI (Herfindahl-Hirschman Index) analysis.

Indices will be developed for:

4. each of the geographic markets or zones;

5. each of the PX and ISO product markets including Energy, Ancillary Services and Imbalance Energy markets;

6. each of the Day-Ahead, Hour-Ahead and Real Time Markets;

7. each of the market conditions such as on-peak and off-peak periods, periods with Congestion and without Congestion, and periods with and without other constraints;

D. Outages and Other Indices

1. Generation Unit and transmission facility Outage indices in comparison with historical averages, with other similar units or facilities, and with other relevant standards;

2. New or unexpected occurrences of Congestion; and

3. Trend comparisons of Market Clearing Prices with fuel prices and other input prices.

Appendix D: Acronyms and Technical Terms

ADR: Alternative dispute resolution; an option contained in market mitigation procedures that usually allows either party to seek an independent, neutral determination of a disagreement.

Ancillary Services Markets: Markets for services necessary to support the transmission of energy from generators to loads, while maintaining reliable operation of the regional bulk power system; includes reserves, automatic generation service, black-start capability, and installed capacity requirements.

Bid mitigation: Ability of the market monitor to modify the bids entered by the market participants. Bid mitigation is different from price caps: with bid mitigation, only bids are modified, and the price is then set according to the market. With price mitigation, the final price itself is modified.

Bid-stack: The tabulation in ascending order of all the bids submitted; this constitutes the aggregate supply within the market.

Bulk power system: The regional electric supply system administered by an ISO or RTO.

CDR: Capacity Deficiency Rate.

Capacity Market: Generation resources that qualify for installed capacity credit.

De-listing of capacity resources: Removal of capacity and energy from the market.

Day-ahead Market: Part of a multi-settlement market system that provides financial certainty for supply offers and demand bids for energy, at a minimum, and often ancillary services.

ECP: Energy Clearing Price.

FERC: Federal Energy Regulatory Commission, responsible pursuant to the Federal Power Act for ensuring that wholesale electricity tariffs are "just and reasonable."

FTR (FCR): Fixed-Transmission Right (Firm Congestion Right); a financial contract that entitles the holder to a stream of revenues (or charges) based on the reservation level and hourly energy price differences across a specific transmission path

HHI: Herfindahl-Hirschman Index; used to evaluate the level of resource ownership concentration of an industry or sector.

ICAP: Installed Capacity.

IIA: Interim ISO Agreement; the "contract" between NEPOOL and ISO-NE, approved by FERC, that specifies the ISO's duties and responsibilities.

IMM: Independent Market Monitor

ISO: Independent System Operator

LBMP or LMP: Location-Based Marginal Pricing or Locational Marginal Price.

Load Pocket: An area served by out-of-merit local generators when the existing transmission system cannot import sufficient power to meet local demand.

Load Response Program: Program structured to increase the responsiveness of demand to conditions in supply (especially decreasing demand during peak times when supply may fall short of demand).

Loss of load: Other term for rolling blackout or rotating feeders.

MAAC: Mid-Atlantic Area Council; establishes rules and reliability guidelines for the PJM bulk power system.

MAR: MMU Activities Report

MMIP: Market Monitoring Implementation Plan

MMP: Market Monitoring Program:

MMU: Market Monitoring Unit

MPC: Market Performance Committee.

MSC: Market Surveillance Committee.

MST: Market Services Tariff.

MSU: Market Surveillance Unit.

NE: New England.

NEPOOL: New England Power Pool.

NERTO: Northeast RTO.

NCPC: Net Commitment Period Cost; used to determine a value for compensation for out-of-merit generation pursuant to Market Rule 17 (ISO-NE).

NPCC: Northeast Power Coordinating Council; establishes rules and reliability guidelines for the bulk power systems in NY, NE, Ontario, Quebec, and the Maritimes.

OA: Operating Agreement

OATT: Open-Access Transmission Tariff

Out-of-Merit Generation: Generation that is dispatched for system reliability reasons that would not otherwise be dispatched economically.

PJM: Pennsylvania, New Jersey, Delaware, Maryland and District of Columbia bulk power system.

PX: Power Exchange (California)

RAA: PJM Reliability Assurance Agreement

Real-Time Market: An electricity market recognizing actual generation dispatch (e.g., as opposed to the day-ahead market).

RTO: Regional Transmission Organization

Soft Cap: A cap on an energy supply bid which can be exceeded with appropriate cost justification. Bids exceeding the soft cap do not set the market clearing price, however bidders will be paid the bid amount.

WSCC: Western Systems Coordinating Council; establishes rules and reliability guidelines for the entire bulk power system west of the Rocky Mountains, including portions of Canada and Mexico.